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FINAL REPORT

ADVANCED COGENERATION TECHNOLOGY ECONOMIC OPTIMIZATION STUDY (ACTEOS)

by

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ABSTRACT

The Advanced Cogeneration Technology Economic Optimization Study (ACTEOS) was undertaken to extend the results of the Cogeneration Technology Alternatives Study (CTAS). Both studies were aimed at providing data which would assist the Department of Energy in establishing R&D funding priorities in the area of advanced energy conversion systems for industrial cogeneration applications. ACTEOS, in particular, employed a mixed integer linear programming model to develop economically optimal cogeneration system designs for representative plants in selected industries (newsprint, writing paper, chlorine and petroleum refineries). Cost comparisons were then made between designs involving advanced cogeneration technologies and designs involving either conventional cogeneration technologies or not involving cogeneration. For the specific equipment cost and fuel price assumptions made in the study, it was found that: (1) coal-based cogeneration systems (both advanced and conventional) offered appreciable cost savings over the no cogeneration case, while systems using coal-derived liquids offered no costs savings; and (2) the advanced cogeneration systems provided somewhat larger cost savings than the conventional systems. Among the issues considered in the study included: (1) temporal variations in steam and electric demands; (2) requirements for reliability/standby capacity; (3) availability of discrete equipment sizes; (4) regional variations in fuel and electricity prices; (5) off-design system performance; and (6) separate demand and energy charges for purchased electricity.

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I. INTRODUCTION

A. Objectives and Scope of the Study

This report presents the findings of the Advanced Cogeneration Technology Economic Optimization Study (ACTEOS). This study was undertaken to extend the results of the Cogeneration Technology Alternatives Study (CTAS), which was performed for DOE's Office of Coal Utilization Systems by NASA's Lewis Research Center (LeRC) with support from JPL. CTAS was aimed at providing a data base which would assist DOE in establishing R&D funding priorities in the area of advanced energy conversion systems for industrial cogeneration applications. Under the CTAS effort, two DOE-sponsored/NASA-contracted studies were carried out by industrial teams led by the General Electric Company and the United Technologies Corporation. In-house evaluations of the contracted activities are being conducted by NASA LeRC. The broad scope of this present study (ACTEOS) is to assist in these evaluations.

The primary objectives of this study have been twofold:

- To provide information to NASA LeRC which will assist them in evaluating advanced energy conversion systems for implementation in optimized industrial cogeneration applications.
- To assist NASA LeRC in quantifying and assessing the advantages of advanced energy conversion system technologies relative to the use of today's commercially available technology.

The primary outputs of this study are:

- Mathematical models for each advanced energy conversion technology considered.

- A cataloged comparison of each industrial process considered under the scenarios of:
  - No cogeneration.
  - Cogeneration assuming the use of currently available cogeneration technologies.
  - Cogeneration assuming the use of advanced cogeneration technologies.
- Operating summaries for each industry/scenario analyzed including:
  - Cogeneration system descriptions.
  - Operating characteristics.
  - Annual cost.

While an effort was made to consider industrial processes which would be representative of various different industries, it is not intended that the economically optimal designs developed for each process would necessarily be applicable to all plants in a given industry.

In order to extend the results of CTAS, the present study has been designed to give increased consideration to the following issues, and to provide insight as to their effect on the attractiveness of industrial cogeneration with advanced systems:

- System designs based on cost minimization, as compared to other design criteria (e.g., heat matching).
- Temporal variations in process steam and electric demands.
- Requirements for reliability/standby capacity.
- Availability of discrete unit sizes.
- Recent fuel price changes.
- Regional variations in fuel and electricity prices.
- Off-design (part load) system performance.

- Separate demand (dollars/kW) and energy (cents/kWh) charges for purchased electricity.

B. Organization of the Report

The main findings and conclusions of this study are provided in Chapter II. In Chapter III, we present an overview of the optimization model used to conduct the analyses in this study. In Chapter IV, details on the performance, costs, and modeling of the energy conversion systems considered in the study are delineated, while in Chapter V, assumptions about costs and prices of the various elements in the optimization model are presented. In Chapter VI, characteristics of the industries and regions are provided. Chapter VII provides details about the optimization results, operating summaries for each case studied and detailed energy flow charts for some of the more interesting cases. Appendix A contains cost and performance data for each of the advanced cogeneration technologies, while Appendix B provides details about the optimization methodology used in the model.

II. SUMMARY AND CONCLUSIONS

A. Overview of Methods

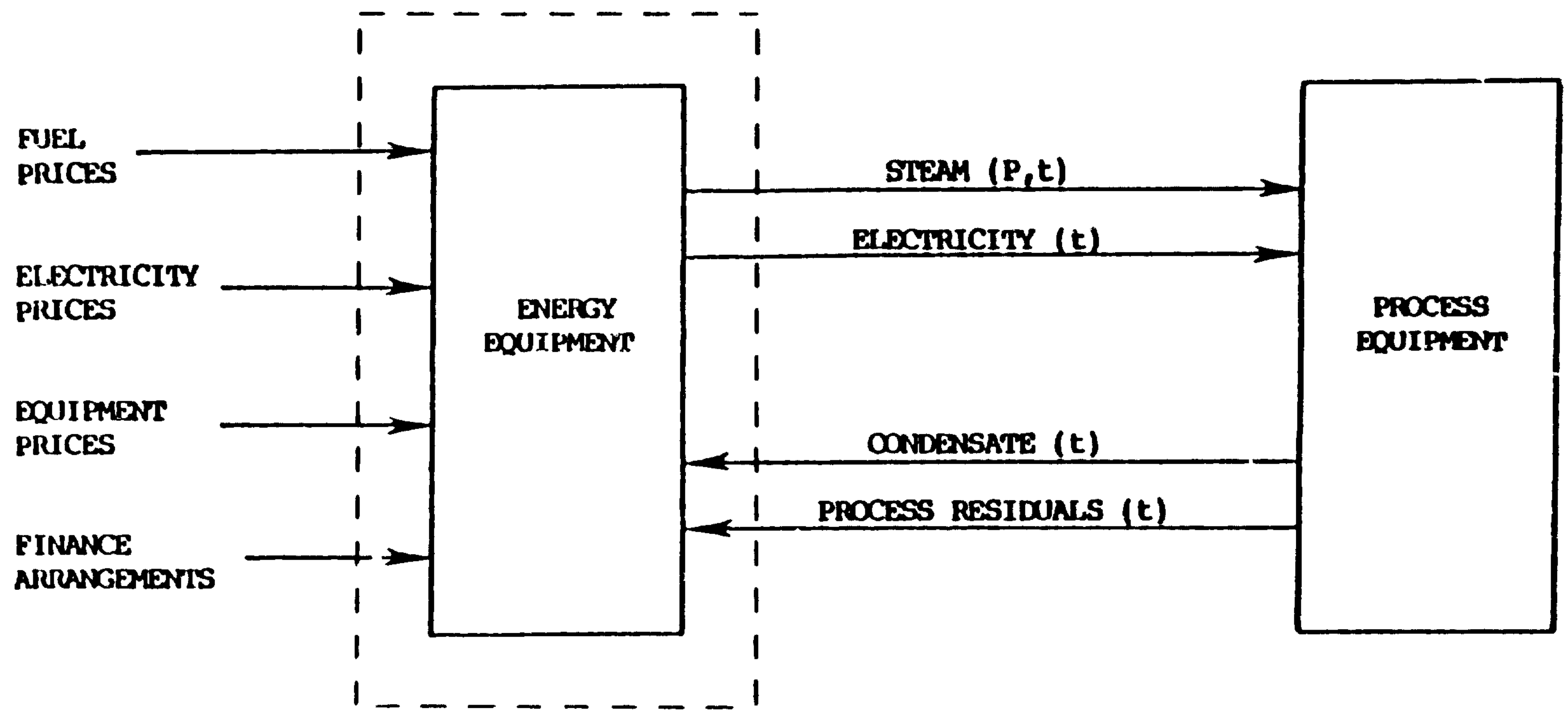
The goal of this study has been to develop economically optimized cogeneration system designs for representative plants in each of four types of industries. For a given industrial facility, the number of design alternatives to be evaluated may be rather large, and the number of possible operating conditions may be essentially infinite. Thus, direct enumeration of all possible design alternatives would not be an efficient way to identify the optimal design.

As an alternative, in this study we have used a mixed integer programming model (MIP) to determine the minimum cost design. The model considers the problems of equipment selection and operation, fuel selection, and purchase or cogeneration of electricity in any combination. Of particular interest is the model's ability to take into account unit size availability in developing the optimal design. The model can also consider the details of the applicable electric utility tariff, including rates for purchased electricity, purchased standby capacity, and buy-back rates for excess cogenerated electricity.

In analyzing a specific manufacturing plant, it is convenient to view the plant as consisting of two parts, viz., energy producing equipment and process equipment. This dichotomy is exhibited in Figure II-1. The energy-producing equipment supplies process steam and electricity (some or all of which may be purchased) to the process equipment in the plant. The steam may be required at several pressures (P), and both the steam and electricity requirements may vary with time (t). For purposes of the MIP model, the process equipment is treated as a "black box", which must be

Figure II-1

Focus of the Optimization Model



P = pressure

t = time

supplied with known quantities of steam and electricity. This "box" may return condensate and/or process residuals which may be used by the energy side of the plant. The focus of the MIP model is on the energy-producing equipment in the plant, as indicated by the dashed line in the figure. That is, the MIP model considers the problem of equipment and fuel selection and equipment operation.

In contrast to traditional design approaches, the model does not necessarily attempt to match either steam or electricity loads. Rather, it selects the equipment and operating program which can supply the required process steam and electricity at lowest cost. The cost concept employed is that of an annualized cost which includes the annualized cost of operation and maintenance, fuel, and purchased electricity over the life of the equipment, plus an annual fixed charge for the capital cost of purchasing and installing any equipment. A design which minimizes the annualized cost would also minimize the discounted present value of all costs. Thus, use of either cost concept would produce the same results and we have used the former concept for convenience reasons.

In order to make a run of the MIP model, three kinds of input data must be provided, as shown in Figure II-2. The first phase of this study called for developing models or characterizations of the different advanced energy conversion systems using data provided by NASA's Lewis Research Center (LeRC). A list of the advanced systems considered is provided in Table II-1. Also shown in Table II-1 are the state-of-the-art (SOA) systems included in the model. Data and models for these systems were

Figure II-2

Elements of the Analysis

PURPOSE

- To identify economically optimized cogeneration system designs for representative plants in different industries.

INPUT

- A description of the energy requirements for the manufacturing plant to be analyzed (i.e., the temporal pattern of its steam and electric demands).
- A description of the cost and performance characteristics of the energy conversion technologies available for use or installation by the plant.
- A set of prices for the different fuels, purchased electricity, equipment and money.

OUTPUT

- Which technologies should be installed (or used).
- How many devices of each type should be installed.
- How the equipment should be operated in each time period.
- How much the system and its operation will cost.
- How much fuel and purchased electricity will be consumed.

Table II-1

Power Systems Included in the MIP Model*

ADVANCED SYSTEMS • AFB steam generators • PFB steam generators** • Open cycle gas turbines with AFB • Open cycle gas turbines with PFB** • Open cycle gas turbines with coal-derived residual • Open cycle gas turbines with integrated gasifier** • Open cycle gas turbines with coal-derived residual for combined cycle application • Closed cycle gas turbines with AFB • Molten carbonate fuel cells with coal-derived distillate** • Molten carbonate fuel cells with integrated gasifier**
STATE OF THE ART SYSTEMS • Conventional steam generators (boilers) with coal, oil or gas • Steam turbines • Gas turbines with natural gas or distillate • Diesel engines

Notes:

*A more detailed description of the technologies can be found in Chapter IV.

**Models were developed for these technologies but were not analyzed during the study due to time and resource constraints.

AFB = Atmospheric fluidized bed.

PFB = Pressurized fluidized bed.

developed as part of an earlier study for EPRI.* To ensure consistency between the advanced and SOA systems, the cost and performance data for the latter were reviewed and revised as part of this study. The models for both types of systems incorporate electric and/or thermal conversion efficiencies for operation at both rated capacity and at less than rated capacity.

B. Major Assumptions in the Study

1. Industrial Processes Considered

The cogeneration systems listed previously were evaluated for representative plant energy requirements in each of four industries. The industries included: newsprint, writing paper (bleached kraft), chlorine, and petroleum refining. Process steam and electricity demands for the representative plants were provided by JPL in the form of load duration curves. In the first three industries above, the load duration curves suggested that time variations in demand could be characterized by three different load conditions: normal, peak, and off-peak. For the petroleum refining industry, four demand conditions were required. To illustrate the process demand asssumptions used in the study, demand conditions during the "normal" period are summarized in Table II-2. Demand conditions in the other time periods can be found in Chapter VI.

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*E. H. Manuel, Jr., M. C. Duff, D. E. Cullen and P. Nanda, Forecasting Inplant Electricity Generation in the Industrial Sector, 1975-2000, RP 942-1, a report to the Electric Power Research Institute by MATHTECH, Inc., 1980.

Table II-2

Process Demands During "Normal" Operating Conditions*

Industry	Production	Electricity (MW)	Steam at 450 Psig (MBtu/hr)	Steam at 150 Psig (MBtu/hr)	Steam at 50 Psig (MBtu/hr)	Hot Water at 140°F (MBtu/hr)	Power to Heat Ratio
Newsprint	1200 tpd	70	--	--	237.0	148.0	0.62
Writing Paper	1200 tpd	40	--	--	380.0	240.0	0.22
Chlorine	600 tpd	90	--	125.0	67.3	--	1.60
Petroleum Refining	250 kbpd	40	1,481.0	109.5	334.5	--	0.07

*Process demands in peak and off-peak periods can be found in Chapter VI.

tpd = tons per day.

kbpd = thousand barrels per day.

MW = megawatts.

MBtu = million btu.

2. Fuel and Electricity Prices

Fuel and electricity prices were calculated for six geographic regions in the U.S. in which there are concentrations of industrial plants of the type considered in this study. Calculations were also made for national (average) prices for analysis at the national level. All prices are for a base year of 1990 stated in 1978 dollars. These calculations were based on the most recent Department of Energy forecast of regional and national prices for fuels and electricity as contained in the report Historical and Forecasted Energy Prices by DOE Region and Fuel Type for Three Macroeconomic Scenarios (DOE/EIA-0184/15), July 1979.*

The levelized price for each fuel and for electricity is calculated by multiplying the present value of expenses on each fuel or electricity by an annualization or capital recovery factor, details of which are provided in Chapter V of the report. The resulting prices for the national level are provided in Table II-3. Prices for each geographic region considered in this study can be found in Chapter V.

3. Equipment Costs

The installed cost for each type of equipment is part of our starting data. Cost data for the advanced equipment were supplied by NASA LeRC, based on data from the CTAS study,** while those for the state-of-the-art equipment were updated from our precursor EPRI model. We assume that operations start in 1990, and installed cost is quoted with respect to this date. All costs and revenues in the model are expressed in terms of 1978 dollars.

* Prices in this report were in 1980 dollars and were converted to 1978 dollars to be consistent with the equipment prices.

**These cost data are provided in Appendix A.

Table II-3

Levelized Fuel and Electricity Prices in 1990

U.S. Average*

(in 1978 dollars)

FUEL	
Gas, Natural or Coal-Derived	$5.28 per 10^6 Btu
Distillate, Petroleum or Coal-Derived	6.84
Residual, Petroleum or Coal-Derived	5.38
Coal, Bituminous	2.12
ELECTRICITY	
Demand Charge	$2.43 per kW per month
Energy Charge	2.99 cents per kWh
STANDBY CAPACITY	$2.00 per kW per month
BUY BACK PRICE (60 percent of selling price at an 80 percent load factor)	2.05 cents per kWh

*Prices for each region can be found in Chapter V.

In calculating the levelized fixed charges corresponding to expenditure on equipment purchase, specific values for various parameters had to be assumed. These are listed in Table II-4. In all cases, the values used were supplied by NASA LeRC. Details of the calculations of the fixed charges are provided in Chapter V.

C. Overview of Results

A total of approximately 50 cases (i.e., industry/region/technology combinations) were analyzed during the study. A summary of the cases considered is shown in Table II-5. The cases were selected by NASA LeRC based on combinations which appeared potentially promising in the CTAS study.

A summary of the results for these cases is provided in the various tables which follow. Tables II-6 to II-10 summarize the total annual cost for each of the cases examined. The total annual cost includes fixed capital charges, O&M cost, fuel cost, purchased electricty and purchased standby electricity costs, less any revenues from the sale of electricity. Tables II-11 to II-15 summarize the components of electricity supply in each case. That is, they show the proportionate use of purchased vs. cogenerated electricity in supplying plant electric demands.

In reviewing the tables which follow, several points should be kept in mind. First, the results shown reflect the specific set of fuel and electricity price assumptions, provided previously in Table II-3. Under a different set of assumptions, the results could of course be quite different. We believe, however, that the price assumptions are realistic. Second, while an effort was made to consider representative plants in each of the four industries, the economically optimal systems identified in this

Table II-4

Parameters Used in the Calculation of Fixed Capital Charges

Parameter	Value
Cost of Capital	5.4 percent
Book Life of Equipment	30 years
Tax Life of Equipment	15 years
Combined Federal, State and Local Income Tax Rate	50 percent
Other Taxes and Insurance	3 percent
Investment Tax Credit	10 percent
Length of Construction Period	Varies with Type of Equipment

Table II-5

Summary of Cases Analyzed

Industry	U.S./ Region	Buy-Back Rate (%)	Technology						
			No Cogen.	SOA Steam	AFB Steam	OCGT w/AFB	OCGT w/CDR	OCGT w/AFB	Combined Cycle
Newsprint	U.S.	60	*	*	*	*	*	*	*
	U.S.	100	*	*	*	–	–	–	–
	Wash.	60	*	*	*	*	*	*	*
	Wash.	100	*	*	*	–	*	–	–
Writing Paper	U.S.	60	*	*	*	*	–	*	*
	Wisc.	60	–	–	–	*	–	*	*
Chlorine	U.S.	60	*	*	*	*	–	*	*
	Texas	60	–	–	–	*	–	*	*
Petroleum Refining	U.S.	60	*	*	*	–	–	*	*
	Texas	60	–	–	–	*	–	*	*

* = Cases analyzed.

study may not necessarily be applicable to all of the actual plants in each industry.

Third, the optimization model used in this study employs an iterative solution procedure. This means that alternative cogeneration system designs are evaluated sequentially, keeping track of the best design found along the way, and ending when one design is proven optimal. It turned out that in evaluating the various steam turbine cogeneration systems, far more computer time was required to prove optimality than had been budgeted. As a result, in these cases the computer runs were terminated before optimality was proven. The results shown for the steam turbine cases are thus for the best steam turbine-based system found, but the possibility remains that an even better steam turbine design may exist.*

1. Cost Comparisons

In reviewing Tables II-6 to II-10, the annual cost summaries, several general patterns appear. First, because of the high price of coal-derived residual (CDR), relative to the price of coal, neither of the systems which use CDR appear competitive on the basis of annualized cost.** These systems include both the open cycle gas turbine with CDR and the combined

*In cases where optimality has not yet been proven, the model provides both the annual cost for the best system found so far, and a lower bound on the annual cost for all remaining alternatives not yet evaluated. The interpretation that should be made is that a lower cost design may possibly exist, but if one does exist, its annual cost would be no lower than the lower bound. In the tables which follow, the lower bound is given in parentheses for those systems not yet proven optimal. A more detailed discussion of the interpretation of the lower bound can be found in Appendix B.

**In contrast, the CTAS study reported favorable findings for the systems using coal-derived liquids. The results are different here because a more recent set of fuel price forecasts was used and as a result the prices assumed for coal-derived liquids are much higher.

Table II-6

Total Annualized Cost in $1,000,000 (1978 $)

Case: U.S. Average Prices; 60% Buy-Back Rate

Technology	Industry			
	Newsprint	Writing Paper	Chlorine	Petrol. Refining
No Cogeneration	37.85	42.21	35.19	66.62
SOA Steam Turbines	29.68 (23.41)*	25.84 (17.67)*	32.97 (27.48)*	65.70 (47.57)*
AFB Steam Turbines	27.92 (23.92)*	23.90 (18.92)*	31.28 (27.63)*	59.26 (49.87)*
Closed Cycle Gas Turbines w/AFB	27.05	23.17	30.48	—
Open Cycle Gas Turbines w/CDR	37.82	--	—	—
Open Cycle Gas Turbines w/AFB	30.00	26.92	31.67	60.11
Combined Cycle Gas Turbines w/CDR	38.47 (33.65)*	41.55*** (38.85)*	**	**

* = Optimal solution not yet attained; lower bound is given in parentheses.

** = No Cogeneration solution was superior.

*** = Same solution as No Cogeneration case, but more package boilers allowed.

SOA = State-of-the-art.
AFB = Atmospheric fluidized bed.
CDR = Coal-derived residual oil.

Table II-7

Total Annualized Cost in $1,000,000 (1978 $)

Industry: Newsprint

Technology	U.S. Average Prices		State of Washington Prices	
	60% Buy Back	100% Buy Back	60% Buy Back	100% Buy Back
No Cogeneration	37.85	37.85	27.46	27.46
SOA Steam Turbines	29.68 (23.41)*	31.52 (23.45)*	21.96 (13.73)*	20.10 (13.91)*
AFB Steam Turbines	27.92 (23.92)*	27.84 (23.65)*	18.49 (13.90)*	18.40 (13.91)*
Closed Cycle Gas Turbines w/AFB	27.05	—	21.43	—
Open Cycle Gas Turbines w/CDR	37.82	—	**	**
Open Cycle Gas Turbines w/AFB	30.00	—	21.83	—
Combined Cycle Gas Turbines w/CDR	38.47 (33.65)*	—	**	—

* = Optimal solution not yet attained; lower bound is given in parentheses.

** = No Cogeneration solution was superior.

SOA = State-of-the-art.
AFB = Atmospheric fluidized bed.
CDR = Coal-derived residual.

Table II-8

Total Annualized Cost in $1,000,000 (1978 $)

Industry: Writing Paper, Bleached Kraft

Technology	U.S. Average Prices 60% Buy-Back Rate	State of Wisconsin Prices 60% Buy-Back Rate
No Cogeneration	42.21	—
SOA Steam Turbines	25.84 (17.67)*	—
AFB Steam Turbines	23.90 (18.92)*	—
Closed Cycle Gas Turbines w/AFB	23.17	22.76
Open Cycle Gas Turbines w/CDR	—	—
Open Cycle Gas Turbines w/AFB	26.92	26.51
Combined Cycle Gas Turbines w/CDR	41.55*** (38.85)*	47.31 (46.84)*

* = Optimal solution not yet attained; lower bound is given in parentheses.

** = No Cogeneration solution was superior.

*** = Same solution as No Cogeneration case, but more package boilers allowed.

SOA = State-of-the-art.
AFB = Atmospheric fluidized bed.
CDR = Coal-derived residual.

Table II-9

Total Annualized Cost in $1,000,000 (1978 $)

Industry: Chlorine

Technology	U.S. Average Prices 60% Buy Back	Texas Prices 60% Buy Back
No Cogeneration	33.19	37.57
SOA Steam Turbines	32.97 (27.48)*	—
AFB Steam Turbines	31.28 (27.63)*	—
Closed Cycle Gas Turbines w/AFB	30.48	32.73
Open Cycle Gas Turbines w/CDR	—	—
Open Cycle Gas Turbines w/AFB	31.67	34.69
Combined Cycle Gas Turbine w/CDR	**	**

* = Optimal solution not yet attained; lower bound is given in parentheses.

** = No Cogeneration solution was superior.

SOA = State-of-the-art.
AFB = Atmospheric fluidized bed.
CDR = Coal-derived residual.

Table II-10

Total Annualized Cost in $1,000,000 (1978 $)

Industry: Petroleum Refining

Technology	U.S. Average Prices 60% Buy-Back Rate	State of Texas Prices 60% Buy-Back Rate
No Cogeneration	66.62	—
SOA Steam Turbines	65.70 (47.57)*	—
AFB Steam Turbines	59.26 (49.87)*	—
Closed Cycle Gas Turbines w/AFB	—	58.64 (56.55)*
Open Cycle Gas Turbines w/CDR	—	—
Open Cycle Gas Turbines w/AFB	60.11	56.64
Combined Cycle Gas Turbines w/CDR	**	**

* = Optimal solution not yet attained; lower bound is given in parentheses.

** = No Cogeneration solution was superior.

SOA = State-of-the-art.
AFB = Atmospheric fluidized bed.
CDR = Coal-derived residual.

cycle system which uses basically the same gas turbine. In both cases, it was almost always less expensive to buy all electricity and generate the required steam with package boilers (the no cogeneration case). We expect that the results for the combined cycle would improve if it employed one of the gas turbine systems which uses coal directly.

In contrast, for the other four types of systems, it was always found to be the case that cogeneration of at least some of the required plant electricity produced cost savings compared to the no cogeneration case (buying all electricity). In particular, the steam turbine systems (using either conventional or AFB boilers) and the open and closed cycle gas turbines with AFB, all provide cost savings over the no cogeneration case. This was found to be true in all industries and regions examined. These systems all use coal directly rather than in liquified form.

In the case of the steam turbine systems, the results for the two types are quite similar. One system uses conventional coal-fired boilers with scrubbers, the other uses an AFB furnace. The annual cost with the AFB furnace appears to be slightly lower in all industries and regions examined. However, none of these cases ran to full optimality and so a definitive cost advantage cannot be claimed.

The two AFB gas turbines also provide cost savings over the base case. Generally, the closed cycle gas turbine exhibited slightly lower annual costs compared to the open cycle system in all industries and regions.

2. Electricity Supply Comparisons

Tables II-11 to II-15 provide a breakdown of how the electric demands were satisfied in each of the cases examined. In reviewing these tables, we will focus on the four systems which showed a cost advantage over the

Table II-11

Components of Electricity Supply
(As a percent of annual demand)

Case: U.S. Average Prices; 60% Buy-Back Rate

Technology		Industry: Newsprint	Writing Paper	Chlorine	Petrol. Refining
No Cogeneration	P	100%	100%	100%	100%
SOA Steam Turbines	P	80*	33*	38*	47*
	G	20	67	12	53
	S	0	0	0	0
AFB Steam Turbines	P	78*	33*	95*	64*
	G	22	67	5	36
	S	0	0	0	0
Closed Cycle Gas Turbines w/AFB	P	48	0	70	—
	G	52	148	30	
	S	0	48	0	
Open Cycle Gas Turbines w/CDR	P	98	—	—	—
	G	2			
	S	0			
Open Cycle Gas Turbines w/AFB	P	71	4	89	0
	G	29	96	11	292
	S	0	0	0	192
Combined Cycle Gas Turbines w/CDR	P	82*	100*	**	**
	G	18	0		
	S	0.07	0		
Annual Electric Demand in Million kWh		592.0	350.4	764.7	334.5

P = Purchased Electricity
G = Self-generated Electricity
S = Electricity Sold to Grid

* = Optimal solution not yet attained; figures are for best solution found.

** = No Cogeneration solution was superior.

Table II-12

Components of Electricity Supply (10^6 kWhr)

Industry: Newsprint

Technology		U.S. Average Prices 60% Buy Back	State of Washington Prices 60% Buy Back
No Cogeneration	P	592.0 = 100%	592.0 = 100%
SOA Steam Turbines	P	471.1 = 80%*	508.8 = 86%*
	G	120.9 = 20%	83.2 = 14%
	S	0.0 = 0%	0.0 = 0%
AFB Steam Turbines	P	461.9 = 78%*	550.4 = 93%*
	G	130.1 = 22%	41.6 = 7%
	S	0.0 = 0%	0.0 = 0%
Closed Cycle Gas Turbines w/AFB	P	285.4 = 48%	287.8 = 49%
	G	306.6 = 52%	306.6 = 51%
	S	0.0 = 0%	2.4 = 0%
Open Cycle Gas Turbines w/CDR	P	581.6 = 98%	**
	G	10.4 = 2%	
	S	0.0 = 0%	
Open Cycle Gas Turbines w/AFB	P	418.3 = 71%	420.9 = 71%
	G	173.7 = 29%	173.7 = 29%
	S	0.0 = 0%	2.6 = 0.44%
Combined Cycle Gas Turbines w/CDR	P	484.8 = 82%*	**
	G	107.6 = 18%	
	S	0.4 = 0.07%	

P = Purchased Electricity
G = Self-generated Electricity
S = Electricity Sold to Grid

* = Optimal solution not yet attained; figures are for best solution found.

** = No Cogeneration solution was superior.

Table II-13

Components of Electricity Supply (10^6 kWhr)

Industry: Writing Paper

Technology		U.S. Average Prices 60% Buy Back	State of Wisconsin Prices 60% Buy Back
No Cogeneration	P	350.4 = 100%	350.4 = 100%
SOA Steam Turbines	P	116.4 = 33%*	—
	G	234.0 = 67%	
	S	0.0 = 0%	
AFB Steam Turbines	P	116.2 = 33%*	—
	G	234.2 = 67%	
	S	0.0 = 0%	
Closed Cycle Gas Turbines w/AFB	P	0.0 = 0%	0.0 = 0%
	G	518.9 = 148%	518.9 = 148%
	S	168.5 = 48%	168.5 = 48%
Open Cycle Gas Turbines w/CDR	P	—	—
	G		
	S		
Open Cycle Gas Turbines w/AFB	P	13.6 = 4%	13.6 = 4%
	G	336.8 = 96%	336.8 = 96%
	S	0.0 = 0%	0.0 = 0%
Combined Cycle Gas Turbines w/CDR	P	350.4 = 100%*	5.3 = 2%*
	G	0.0 = 0%	350.4 = 100%
	S	0.0 = 0%	5.3 = 2%

P = Purchased Electricity
G = Self-generated Electricity
S = Electricity Sold to Grid

* = Optimal solution not yet attained; figures are for best solution found.

Table II-14

Components of Electricity Supply (10^6 kWhr)

Industry: Chlorine

Technology		U.S. Average Prices 60% Buy Back	State of Texas Prices 60% Buy Back
No Cogeneration	P	764.7 = 100%	764.7 = 100%
SOA Steam Turbines	P	674.3 = 88%*	—
	G	90.4 = 12%	
	S	0.0 = 0%	
AFB Steam Turbines	P	723.1 = 95%*	—
	G	41.6 = 5%	
	S	0.0 = 0%	
Closed Cycle Gas Turbines w/AFB	P	533.0 = 70%	501.9 = 66%
	G	231.7 = 30%	262.8 = 34%
	S	0.0 = 0%	0.0 = 0%
Open Cycle Gas Turbines w/CDR	P	—	—
	G		
	S		
Open Cycle Gas Turbines w/AFB	P	677.1 = 89%	677.1 = 89%
	G	87.6 = 11%	87.6 = 11%
	S	0.0 = 0%	0.0 = 0%
Combined Cycle Gas Turbines w/CDR	P	**	**
	G		
	S		

P = Purchased Electricity
G = Self-generated Electricity
S = Electricity Sold to Grid

* = Optimal solution not yet attained; figures are for best solution found.

** = No Cogeneration solution was superior.

Table II-15

Components of Electricity Supply (10^6 kWhr)

Industry: Petroleum Refining

Technology		U.S. Average Prices 60% Buy Back	State of Texas Prices 60% Buy Back
No Cogeneration	P	334.5 = 100%	334.5 = 100%
SOA Steam Turbines	P	156.4 = 47%*	—
	G	178.1 = 53%	
	S	0.0 = 0%	
AFB Steam Turbines	P	213.8 = 64%*	—
	G	120.7 = 36%	
	S	0.0 = 0%	
Closed Cycle Gas Turbines w/AFB	P	—	0.0 = 520%*
	G		1748.6 = 523%
	S		1414.1 = 423%
Open Cycle Gas Turbines w/CDR	P	—	—
	G		
	S		
Open Cycle Gas Turbines w/AFB	P	0.0 = 0%	0.0 = 0%
	G	975.3 = 292%	975.3 = 292%
	S	640.8 = 192%	640.8 = 192%
Combined Cycle Gas Turbines w/CDR	P	**	**
	G		
	S		

P = Purchased Electricity
G = Self-generated Electricity
S = Electricity Sold to Grid

* = Optimal solution not yet attained; figures are for best solution found.

** = No Cogeneration solution was superior.

base case; that is, a cost savings resulting from cogenerating part of the electric power required.

The first two systems of interest are the steam turbine systems, one using conventional coal-fired boilers with scrubbers and the other using an AFB furnace. The pattern which appears is that within a given industry, the two systems are very similar in terms of the mix of purchased and cogenerated electricity. This is what one would expect since the heat to power output ratios for the two systems are similar. The main differences that arise are due to differences among industries. Thus, industries with small steam demands had little cogeneration since it is not economical to generate excess steam. For example, production of cogenerated electricity is lowest in the chlorine industry which has the lowest steam demand among the four industries. The next larger amount of cogenerated electricity occurs in the newsprint industry which also has the next largest steam demand. Still larger amounts of both cogeneration and steam demand occur in the writing paper industry.

The one unique case in the steam turbine cases is the petroleum industry. This industry has the highest level of steam demand among the four industries. However, 77 percent of the steam is required at 450 psig which makes it unsuitable for cogeneration with the steam turbines included in the model.* The steam demand at or below 150 psig is comparable to that found in the newsprint industry, and thus, as one might expect, the levels of cogeneration in these two industries (petroleum and newsprint) are similar. We expect that the results for the petroleum industry would improve if an extraction point at 450 psig was added to the steam turbines.

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*The highest extraction pressure for steam turbines included in the model is 150 psig.

The other two systems of particular interest are the open and closed cycle gas turbines with AFB. Compared to the steam turbine systems, the gas turbines have a higher ratio of power to heat output. As might be expected, then, when the steam requirement is matched, the gas turbine systems result in a larger amount of cogenerated electricity in all four industries, compared to the steam turbine systems. Between the two gas turbine systems, the closed cycle system exceeds the open cycle system in the amount of cogeneration. This was found to be true in all industries and regions. Again, this result might be expected since the closed cycle system has a higher power to heat output ratio.

3. Electricity Sales to the Grid

Another point of interest is the quantity of electricity sold to the grid when using each of the four cost competitive systems. Note that with the two steam turbine systems, sales back to the grid did not occur in any of the four industries. With the steam turbines, given their low power to heat output ratio, the required steam demand in each industry did not support full cogeneration of the plants' own electricity requirements. Hence, no electricity was produced for sale. This result is contingent upon two critical assumptions, however. The first is that the buy-back rate is 60 percent of the grid selling price; a higher buy-back rate may encourage generation for sale. The second assumption is that steam and electric demands fall off at equal rates at lower levels of production by the firm. If it is actually the case that electric demands decline somewhat faster (for example, because steam is used in part for space heating), then opportunities for electricity sales may arise in the off-peak periods.

With the two gas turbine systems, we observe fairly substantial levels of electricity sales in the writing paper and petroleum refining industries. The closed cycle system produces electricity for sale in both industries. The open cycle system generates electricity for sale in the petroleum refining industry. These results are consistent with the ratio of power to steam required in the four industries. The lowest power to steam ratio occurs in the petroleum refining industry and hence it would be the first industry where one would expect to see sales occurring. The next higher power to steam ratio is found in the writing paper industry. This is followed by the newsprint industry and then the chlorine industry.

4. Load Following Characteristics and Unit Sizes

It is often common practice to design a cogeneration system by sizing the equipment to meet the steam demand. The difference between the plant's electric demand and the electricity available by cogeneration is then met by purchases from the grid. Or alternatively, if excess cogenerated electricity is available, it may be sold to the grid. The MIP model does not follow this practice. Rather, it examines all possible design configurations and selects the one which minimizes total annualized cost. It is interesting to note, however, that the cost-minimizing designs in about half of the cases examined are in fact ones in which the equipment is sized to meet the peak steam demand.

Exceptions to the general pattern described above usually occurred as a result of the equipment being available only in a selected number of discrete sizes. The case involving open cycle gas turbines with AFB in the chlorine industry is typical of this situation. In that particular case, the peak demand for steam and hot water totals 211.5 MBtu per hour. The open cycle AFB systems in the model are rated at 10 MW(e), 30 MW(e), 50

MW(e) and 100 MW(e). The peak electric demand is 99 MW. When operated at rated capacity, the 10 MW turbine produces 157 MBtu/hr of process heat; two of the 10 MW units or one of the 30 MW units would thus generate an excess of steam compared to the required steam demand. The model, as a result, determined that it would be less expensive to install the 10 MW device and supply the remaining steam demand with package boilers. The alternative would have been to install two 10 MW units and run them at part load, or run them at full load and dump waste steam. Thus, in this particular case, the optimal design is "custom-tailored" to unit size availability and the sizing matches neither the peak steam nor electric demand, although the peak steam demand influences the design.

The fact that unit size availability dictated the specifics of the design in a fair number of cases has an important implication. In particular, it means that the level of cogeneration likely to develop will depend in part on insuring that the advanced cogeneration systems are made commercially available in a full complement of unit sizes. Furthermore, it means that our results are to some extent influenced by the sizes we assumed in the model. These sizes, which were chosen to be representative, do not necessarily include all of the sizes that might be commercially available in the future. Our specific assumptions are detailed in Chapter IV.

5. Standby Electric Capacity

In 30 of the cases examined, electricity was cogenerated in some amount. In 23 of those cases, standby electric capacity was purchased to back up the cogeneration system. Thus, in more than three-fourths of the cases, the availability of standby service contributed to the decision to cogenerate.

Of the seven cases where no standby capacity was purchased, five were petroleum refining cases involving gas turbines. The high level of steam demand in this industry supported a more than adequate on-site electric generation. Thus, no standby service was required, no purchased power was required, and in fact, substantial sales back to the grid were possible.

D. Conclusions

The findings and conclusions of this study, for the representative plants assumed, are summarized below. It should be kept in mind that as we have noted earlier, these findings are critically dependent upon the specific price and process demand relationships assumed in the study. The findings may be substantially different under a different set of assumptions.

- Cogeneration systems which use coal directly offer appreciable cost savings over the no cogeneration case; systems which use coal-derived liquids offer no cost advantages with the fuel and electricity price assumptions used in this study.

- Among the four systems which offer cost savings, the cost differences among the systems are small. The AFB steam turbine systems provided somewhat larger cost savings than the SOA steam systems (recall, however, that the steam turbine cases did not run to optimality); the closed cycle gas turbines with AFB provided somewhat larger cost savings than the open cycle gas turbines with AFB.

- Across industries, the rankings of the systems based on annual cost do not change appreciably. The main variation observed across industries is in the relative mix of purchased vs. cogenerated electricity. That is, as the heat to power demand ratio increases, the proportionate use of cogenerated electricity increases. Equipment sizing and operating strategies also varied across industries.

- The AFB gas turbine systems result in a larger quantity of cogenerated electricity than the steam turbine systems in all industries. The AFB gas turbine systems more often resulted in sales of electricity to the grid. No sales occurred with either steam turbine system in any industry examined.

- Variations in process energy requirements appear to be more important than variations in regional energy prices in determining the relative mix of purchased and cogenerated electricity.

- In about half of the cases, the best system turned out to be one which was sized to match the peak steam demand. In the other cases, the optimal system generally produced less than the peak steam demand and less than the peak electric demand. The remaining energy requirements were met by package boilers and purchased electricity. In the latter cases, unit size availability dictated the specifics of the design. Hence, the commercial attractiveness of advanced cogeneration systems may depend importantly on making a full complement of unit sizes available.

- In cases where the steam demand was not sufficient to allow cogeneration of the full electric demand, it was cheaper to buy the extra electricity required. That is, it was not economical to generate excess steam that was not required to satisfy steam demands. Or equivalently, it was not economical to size the system to match the peak electric demand.

- In cases where cogeneration was economical, and where the steam demand was more than adequate to support cogeneration of the full electric demand, sales back to the grid occurred.

- The optimal design generally involved the purchase of standby electric capacity rather than the installation of redundant capacity on site. Hence, the availability of standby service at reasonable rates appears to be of considerable importance.

- Cases with buy-back prices set at 100 percent of the grid selling price showed larger sales of cogenerated electricity to the grid. However, this may be an artifact of the model (it allows standby charges to be avoided).

III. OVERVIEW OF THE OPTIMIZATION MODEL

This chapter provides a non-mathematical description of the mixed integer programming (MIP) model that was used to conduct the analyses in this report. The MIP model was one product of an earlier study for the Electric Power Research Institute (EPRI), as referenced previously in Chapter II. The model used in the current study is similar to the version developed for EPRI except for primarily the following changes: cost and performance data on advanced cogeneration systems have been incorporated; electricity tariffs have been simplified; and the solution variables defining the number of units of each equipment type have been constrained to be integer rather than continuous. The detailed mathematical formulation of the MIP can be found in Section 12 of the report cited above. This chapter draws heavily on Section 4 of that report.

As discussed previously in Chapter II, the MIP model is able to select the cost-minimizing combination of equipment from state of the art and advanced equipment options. The fuels and purchased electricity required to supply a manufacturing plant's demands for process steam and electricity are also selected. The model considers the problems of equipment selection and operation, fuel selection, and purchase or self-generation of electricity. The model can take into account the details of the applicable electric utility tariff, including the existence of separate peak demand and energy charges, and declining block rates. The model can also consider whether to purchase standby electric capacity and/or sell excess power back to the grid.

A. Focus of the MIP Model

In analyzing a specific manufacturing plant, it is convenient to view the plant as consisting of two parts. As shown in Figure III-1, one side of the plant contains energy-producing equipment. It supplies process steam and electricity (some of all of which may be purchased), to the process equipment in the plant. As shown in the figure, the steam may be required at several pressures (P), and both the steam and electricity requirements may vary with time (t).

The other side of the plant contains the process equipment. Depending on the type of industry, the equipment may include devices ranging from digesters and dryers in a pulp and paper mill to distillation columns in a petroleum refinery or petrochemical plant. For purposes of the MIP model, we treat all process equipment as contained in a black box. The "box" must be supplied with some known quantities of steam and electricity. It may return condensate and/or process residuals which can be used by the energy side of the plant. However, the inner workings of the black box are not considered in the MIP.

The focus of the MIP model is on the energy-producing equipment in the plant. It considers the problem of equipment selection, fuel selection, and equipment operation.

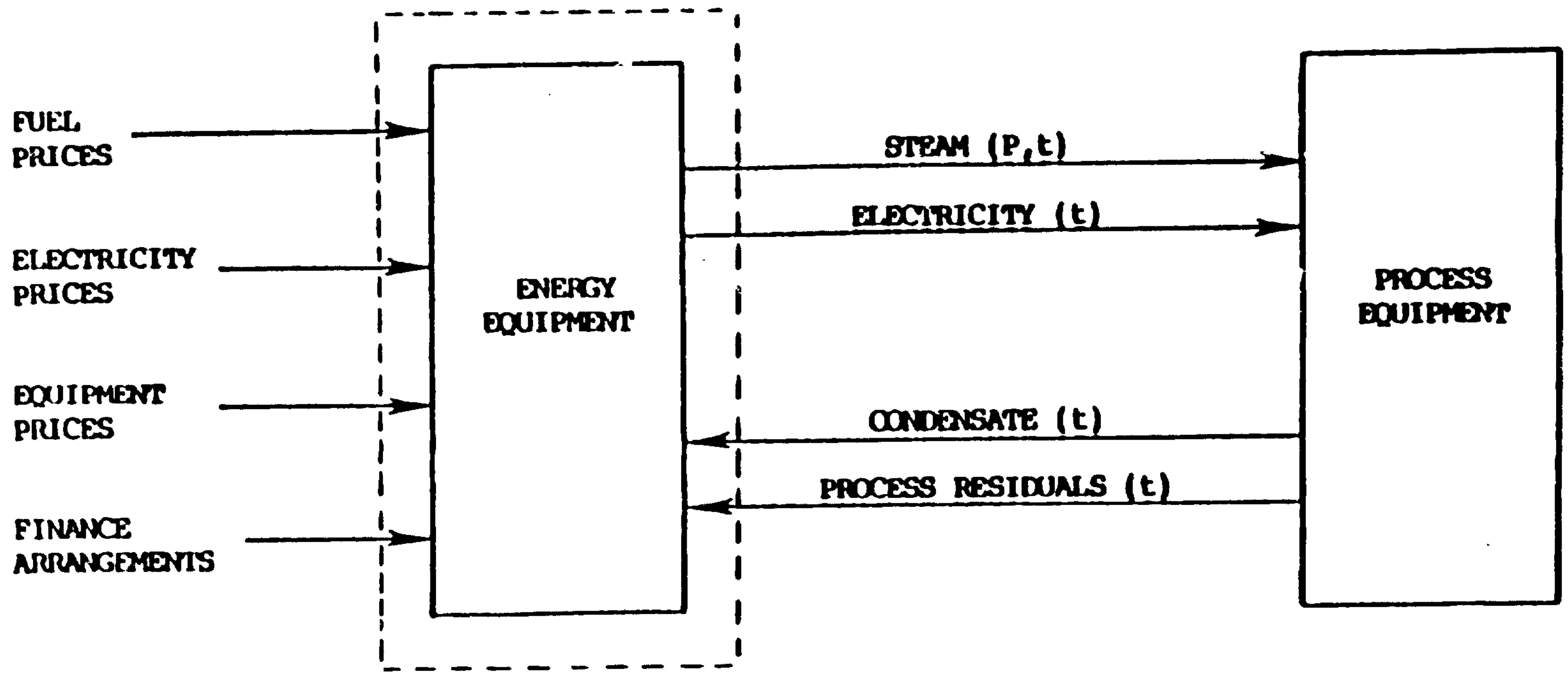
B. Data Input and Model Output

In order to make a run of the MIP model, the model must first be provided with three kinds of input data:

- A description of the energy requirements for the manufacturing plant to be analyzed (i.e., the temporal pattern of its steam and electric demands).

Figure III-1

Focus of the Optimization Model



P = pressure
t = time

- A description of the energy conversion technologies available for use or installation by the plant in terms of performance and capital costs.
- A set of prices for the different fuels, purchased electricity, equipment, and money.

The MIP model is then able to determine:

- Which technologies should be installed (or used).
- How the equipment should be operated in each time period.
- How much the system and its operation will cost.
- How much fuel and purchased electricity will be consumed.

As currently formulated, the MIP model selects the equipment and operating program which can supply the required process steam and electricity at lowest cost. The cost concept employed is that of a levelized annual cost. The levelized annual cost includes the following components: the levelized annual cost of operation and maintenance, fuel, and purchased electricity over the life of the equipment; plus an annual fixed charge for the capital cost of purchasing and installing any equipment. Investment decisions based on annualized cost will be equivalent to decisions based on discounted present value methods.

C. Formulation of the Model

Without going into great detail, it is possible to illustrate the general structure of the optimization model. The model includes primary variables for the type of equipment and number of units selected. There are also variables for production of steam and electricity and purchases of electricity and fuel. A solution of the MIP model would consist of a specific setting of value for each of these variables.

The MIP model also incorporates primary constants. The constants include the prices at which fuels, electricity and equipment can be purchased or sold. They also include the quantities of steam and electricity required by the plant in each time period as well as the capacities and conversion efficiencies of each equipment type available. These numbers are constant for a given run of the MIP, although they can of course be changed from run to run.

Finally, the MIP model incorporates primary constraints. The constraints ensure that equipment is operated within the physical limitations of each device. They ensure that capacity is sufficient to meet demand and that energy balances are satisfied. The constraints are also used to incorporate the declining block structure of electric utility tariffs.

As currently formulated, the objective function of the MIP represents the annualized total cost of energy for the plant. It includes the cost of: fuel, any purchased electricity, any purchased standby capacity, installed equipment, operation and maintenance, less any revenues from the sale of excess electricity. A solution of the MIP thus identifies the system and operating program which is optimal in terms of having the lowest annualized cost. Cost minimization is used as the decision criterion since it most likely reflects the behavior of individual firms. However, other criteria, such as cost minimization, subject to a capital budget constraint can easily be incorporated in the model.

In a later section, an example run of the MIP model is presented. Before discussing the example, however, we will briefly summarize the types of data used in the model. The data include: price and performance data for energy conversion technologies, prices for fuels and electricity, and

process demands for steam and electricity. These three groups of data are summarized in the next three sections, and discussed more fully in later chapters.

D. Technology Data

In this section, we will briefly summarize the type of technology data included in the MIP. A more detailed description of how the data are represented in the model can be found in Chapter IV.

1. Device Types

The MIP model includes two sets of technologies: state-of-the-art (SOA) technologies and advanced technologies. Included among the SOA technologies are most of the commonly used types of power-producing equipment, and commonly used design configurations for each of the equipment types. The SOA technologies included are:

- Fossil-fuel-fired steam generators (boilers),
- Steam turbine generators,
- Combustion turbine generators, and
- Diesel engine generators.

The design options available to the MIP for these devices are summarized later in Table IV-1. Note that the sizes available would accommodate the full spectrum of power demands that one now finds in the industrial sector. Demands as low as 50 kW or 5,000 lb/h of steam can be met, as can demands in excess of 500 MW or 5,000,000 lb/h by use of multiple unit installation.

A second feature of the listed design options is the assumption that process steam requirements would typically be for either 50 psig or 150

psig steam. Various industrial surveys have indicated that low and medium temperature process heating requirements found in industry are typically in the 30-70 psig range and 125-175 psig range; 50 and 150 psig have been chosen as representative. The model can accommodate process steam requirements at higher temperatures and pressures by desuperheating one of the high-pressure steams (e.g., the 600 psig/750^{O}F steam).

The advanced technologies included in the MIP are shown later in Table IV-2. These technologies include:

- AFB/PFB* steam generators
- Advanced open cycle gas turbines
- Closed cycle gas turbines
- Molten carbonate fuel cells.

Note that the steam temperature/pressure combinations and unit sizes have been selected to match the design options available for the SOA systems. The characteristics of these systems are described in more detail in Chapter IV.

2. Cost and Performance Parameters

For each device type and size, the following cost and performance parameters are included in the MIP:

- Capital cost for purchase and installation.
- Annual operation and maintenance cost (O&M), exclusive of fuel costs.

*Atmospheric fluidized-bed (AFB) and pressurized fluidized-bed (PFB).

- Fuel consumption at rated output.
- Fuel consumption at less than rated output.
- Minimum and maximum output (steam or electric).
- Minimum and maximum exhaust flows (steam turbines only).
- Maximum throttle flow (steam turbines only).

The effects of investment tax credits, interest during construction, depreciation methods, taxes, other miscellaneous costs, and corporate discount rates are all incorporated into a fixed charge rate which is applied to the original capital cost. The computation of the fixed charge rate is discussed in Chapter V.

E. Fuel and Electricity Prices

1. Purchased Fuels

The MIP model incorporates four purchased fuels including:

- Residual oil (petroleum or coal-derived)
- Distillate/diesel oil (petroleum or coal-derived)
- Gas (natural or coal-derived)
- Bituminous coal.

The fuels are assumed to be purchased at some fixed price per million Btu. The fixed price can be set to reflect fuel price escalation over time by computing an equivalent levelized price. The details of this calculation are described in Chapter V.

2. Waste Fuels

The model also incorporates waste fuels such as bark or hogged wood in the paper industry. The waste fuels can be used to generate steam in

appropriately designed steam generators. Since the waste fuels are available as by-products of the manufacturing process, we have assumed that their price is zero.* However, we impose limits on the quantity of waste fuel that can be consumed, the units being determined by both the type and size of manufacturing plant under consideration.

3. Purchased Electricity

Most utilities sell electricity to industrial customers under tariffs which take into account both the quantity of electricity purchased (kWh) and the peak demand (kW) which the customer imposes on the utility. Utilities which use a "Hopkinson" tariff compute a customer's bill by applying separate charges for energy (kWh) and for demand (kW). The energy and demand charges may vary with the quantities involved, or with the time when the purchase occurs. For example, under a declining-block Hopkinson tariff, the price per kWh and the price per kW decline with increases in consumption. An additional fixed cost, or "customer charge," is also often applied regardless of the level of use.

Another widely used tariff is the "Wright" tariff. Under this form of tariff, the customer is billed on the basis of kWh consumed. However, the price per kWh may decline both with increased quantities purchased and with increases in the kWh consumed per kW of peak demand.

In this study, we have assumed that electricity is sold according to a tariff which provides for separate peak demand (kW) and energy (kWh)

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*In some industries, the process residuals may require disposal at some cost if they are not consumed as fuel. Hence, it can be argued that the correct price for waste fuel should be a negative price equal to the unit cost of disposal. However, we have not incorporated this additional refinement in the model to date.

charges. The peak demand charge is assumed to be a fixed amount per kW per month (e.g., \$2.43/kW/month), and the energy charge a fixed amount per kWh (e.g., 2.99 cents/kWh). The specific prices assumed for each region of the country are discussed in Chapter V.

4. Purchased Standby Capacity

Many industries require a highly reliable supply of electricity. Aluminum plants and chlor-alkali plants, as an example, use electrolytic processes in which severe equipment damage would occur in an electrical outage. Other industries may not experience damage, but would experience a loss of output. Hence, self-generation in these industries is made reliable either through the provision of backup generating capacity on site, or through the purchase of standby electric capacity from the utility. Both of these options are allowed in the MIP.

Utilities which permit industrial customers to buy electricity on a standby basis generally have a separate tariff for this service. Under these tariffs, a monthly charge is typically made for the amount of standby capacity for which the customer contracts. Standby capacity tariffs typically look like the demand (kW) part of a Hopkinson tariff. We have included a standby tariff in the MIP in the form of a fixed monthly charge per kW. The specific price assumed is \$2.00 per kW per month (see Chapter V).

5. Electricity Sales

The MIP model allows a manufacturing plant the option of selling electricity back to the electric utility grid. Revenues obtained from sales are then deducted from the annual energy cost of the plant. This

means that the selection of the minimum cost system may be influenced by the price at which excess electricity can be sold.

The price for sales, the so-called buy-back rate, is a parameter of the MIP that can be varied from run to run. As currently formulated, the buy-back rate is a single average price per kWh. This price can be varied to consider different scenarios.

F. Process Demands

Process steam and electricity demands are represented in the MIP model as constraints. That is, the energy equipment chosen, together with any purchased electricity, must be able to satisfy all of the plant demands in every time period.

While the number of time periods in the model can be arbitrary, in this study we have assumed that three or four time periods can adequately characterize typical variations in process demands. For example, in a three time period problem, one period is taken to be representative of peak demands, a second period is used to represent normal demand conditions, and the third period reflects off-peak demands.

G. An Example Run

To illustrate the capabilities of the MIP model, one of the cases considered in this study will be reviewed in detail. The case to be examined is the writing paper plant facing U.S. average prices and allowed to sell electricity back to the grid at 60 percent of the average price for purchased electricity. The plant has a production capacity of 1,200 tons per day; it occasionally operates above or below capacity, depending on market demand for product. The plant's requirements for steam, hot water and electricity are summarized in Table III-1.

In the particular case to be examined, the plant will be allowed to choose from among the following options, in any combination:

Table III-1

Process Energy Demands

Production Level (Tons/Day)	Hours Per Year	Electricity (MW)	50 Psig Steam (MBtu/hr)	Hot Water @ 140°F (MBtu/hr)
1,320	1,314	44.0	418.0	264.0
1,200	6,351	40.0	380.0	240.0
1,056	1,095	35.2	334.4	211.2

- Install package boilers firing either oil or gas.
- Install advanced closed cycle gas turbines with AFB and heat recovery boilers.
- Purchase electricity.
- Purchase standby electric capacity.

When the MIP model was applied to this case, the following options were selected:

- Install two 30 MW gas turbines with heat recovery boilers.
- Install five 50 psig package boilers firing natural gas.
- Purchase no electricity.
- Purchase 14 MW of standby capacity.

The operation of the equipment in each time period is recommended to be as follows. In the peak demand period, the gas turbines should be operated at full output, producing 60 MW of electricity. Only 44 MW are required on-site, so 16 MW can be sold back to the grid. Since the

reliability requirement is that a device outage should not restrict electrical requirements, the plant buys 14 MW of standby, that being the peak on-site demand placed on the second unit. The gas turbines also supply about 89 percent of the required steam and hot water. The remainder is supplied by the package boilers.

In the normal demand period, the gas turbines should continue to be operated at full capacity. However, since electrical demand falls off to 40 MW, sales back to the grid can be increased to 20 MW. With steam and hot water demands also reduced, the gas turbines can now supply nearly 98 percent of the requirements, with the remainder coming from the package boilers.

In the off-peak demand period, steam demand has fallen to the point that the package boilers can be shut off completely, with all steam and hot water supplied by heat recovery off the gas turbines. Turbine output is also reduced to 53.9 MW, with 35.2 MW used on-site and 18.7 MW sold to the grid.

In the above mode of operation, the annual energy cost of the plant is $23.17 million (in 1978 dollars). The components of this annual cost include:

	Million Dollars
• Fixed capital charges and O&M	
- Gas turbines	$ 9.40
- Package boilers	0.157
• Fuel	
- Coal	15.68
- Gas	1.05
• Standby electric capacity	0.336
• Revenue from electricity sales	(3.45)
	$23.17

IV. ENERGY CONVERSION SYSTEMS

The energy conversion systems that form the technology base for the model fall into two broad categories. There are the advanced technologies and the state-of-the-art technologies. Data for the advanced systems were provided by NASA/LeRC, and those for the SOA systems were carried over from our earlier EPRI model, with calibration to ensure consistency between the two data sets.

The energy conversion systems included in the advanced technologies are:

1. Advanced open cycle gas turbine with coal derived residual fuel;
2. Advanced open cycle gas turbine with integrated gasifier;
3. Advanced open cycle gas turbine with AFB;
4. Advanced open cycle gas turbine with PFB;
5. Advanced closed cycle gas turbine with AFB;
6. Molten carbonate fuel cell with coal derived distillate fuel;
7. Molten carbonate fuel cell with integrated gasifier;
8. Advanced open cycle gas turbine subsystem for combined cycle;
9. AFB furnace subsystem for an AFB steam turbine system; and
10. PFB furnace subsystem for PFB steam turbine system.

Each of the first seven systems is capable of cogenerating electricity and steam at different pressures, as well as hot water at 140°F. The combined cycle gas turbine subsystem generates only high pressure steam, at 850 psig/825°F and 1450 psig/950°F, in addition to electricity. The high

pressure steam is then used by a steam turbine to generate both electricity and low pressure steam.

Included in the state-of-the-art technologies are:

1. Steam generators — package and field erected boilers;
2. Steam-turbine generators;
3. Gas turbine generators; and
4. Diesel generators.

Table IV-1 gives the equipment combinations available under advanced technologies, and Table IV-2 does the same for the state-of-the-art technologies.

A. Technology Data

Performance (and cost) data for the advanced technology systems were provided by NASA/LeRC. As an example, data for the closed cycle gas turbine with AFB are shown in Table IV-3. The performance data provided include for each device size the net electrical efficiency, the net steam and hot water production per unit of fuel input, and the variation of these performance characteristics at partial loads. The electrical efficiency figure represents the net power output per unit of fuel input. The steam and hot water figures represent the fraction of input fuel energy which is converted to steam and hot water; these latter figures are thus incremental production rates in that they are additions to any energy that may already be present in the feedwater. The part-load performance data represent the fraction of full-load conversion efficiencies which can be obtained at the indicated percent of full-load output.

The steam production rates at each pressure level can be interpreted as follows. The first column indicates the maximum amount of 600 psig

Table IV-1

Advanced Power Equipment

AFB/PFB Steam Generators

Steam Conditions:	600/750, 850/825, 1450/950 (psig/°F)
Unit Sizes:	100,000 to 1,700,000 (lbs/hr)

Open Cycle Gas Turbine-Generators

Fuel Alternatives:	AFB, PFB, coal-derived residual, integrated gasifier
Heat Recovery:	Optional, at 600, 450, 150 or 50 psig, or hot water
Unit Sizes:	1,000 to 100,000 (kW)
Combined Cycle:	Optional, at 850, 1450 psig

Closed Cycle Gas Turbine-Generators

Fuel Alternatives:	AFB
Heat Recovery:	Same as open cycle systems
Unit Sizes:	10,000 to 100,000 (kW)

Molten Carbonate Fuel Cells

Fuel Alternatives:	Coal-derived distillate, integrated gasifier
Heat Recovery:	Optional, at 600, 450, 150 or 50 psig, or hot water
Unit Sizes:	1,000 to 100,000 (kW)

Table IV-2

State-Of-The-Art Power Equipment

Steam Generators

Fuel Alternatives:	Coal, residual, distillate, natural gas, process residuals
Steam Conditions:	50/298, 150/366, 300/422, 600/750, 850/825, 1450/950 (psig/°F)
Unit Sizes:	5,175 to 1,700,000 (lbs/hr)

Steam-Turbine Generators

Throttle Conditions:	600/750, 850/825, 1450/950 (psig/°F)
Exhaust Conditions:	150, 50 (psig), 4" Hg.
Extraction Conditions:	150 (psig)
Unit Sizes:	5,000 to 100,000 (kW)

Gas Turbine-Generators

Fuel Alternatives:	Natural gas, distillate
Heat Recovery:	Optional, at 600, 450, 150 or 50 psig, or hot water
Unit Sizes:	1,000 to 100,000 (kW)

Diesel Generators:

Fuel Alternatives:	Diesel fuel
Heat Recovery:	Optional, at 50 psig, or hot water
Unit Sizes:	50 to 8,800 (kW)

Table IV-3

ECS: Advanced Closed Cycle Gas Turbine With AFB

Size	Full Load Performance						Costs	
	Efficiency n	Q Process/Q Fuel-In					Capital Cost $/kWe	O&M Cost $/kW-hr
		600 psig	450 psig	150 psig	50 psig	Hot Water		
10 MWe	0.230	0.322	0.027	0.064	0.044	0.137	1,300.0	5.6×10^{-3}
30 MWe	0.240	0.320	0.057	0.030	0.043	0.140	1,009.7	5.6×10^{-3}
50 MWe	0.240	0.320	0.057	0.030	0.043	0.140	897.8	5.6×10^{-3}
100 MWe	0.240	0.320	0.057	0.030	0.043	0.140	765.5	5.6×10^{-3}

% of Load	Part Load Performance as a Fraction of Full Load Performance					
	Efficiency n	600 psig	450 psig	150 psig	50 psig	Hot Water
80	1.000	1.000	1.000	1.000	1.000	1.000
60	0.983	1.005	1.005	1.005	1.000	1.007
30	0.909	1.027	1.027	1.027	1.022	1.030

saturated steam that could be produced from the reject heat. In some systems, such as the open cycle gas turbines, all of the reject heat can be recovered in this manner. In other systems, however, there may be some reject heat remaining; and if this is the case, then the second column shows the maximum amount of 450 psig saturated steam that could be produced from the remaining reject heat. If there is any useful heat still remaining, the maximum amount of 150 psig saturated steam producible is shown in the third column and similarly on down the line for 50 psig steam and hot water.

We used regression techniques to find the straight line that best approximates (in the least squared errors sense) the part-load performance points given. This was done in order to find the part-load performance at any arbitrary fraction of full-load output. For each conversion system, a different part-load performance approximation was derived for electricity, hot water, and each of the steam outputs. These approximations are linear in the level of operations (from 25 percent to 100 percent of full-load rating) and so all we need to describe each is a slope and an intercept. These are given in Table IV-4a and IV-4b.

B. Technology Modeling — Input-Output Equations

Basically our technology model is a series of well-defined steps for deriving input requirements in Btu units given a specified level of demand. For a system with more than one output, the model also specifies a well-defined relationship between the secondary outputs and the input energy. Thus, for a system whose primary output is steam, the technology model gives a way of deriving required fuel input in Btu, given that a specified Btu amount of steam of certain pressure-temperature conditions is to be produced. For steam-turbine generators the output specified is

Table IV-4

a) Part Load Equations for Advanced Turbines

Turbine Type \ Product	Fuel Input a = Intercept b = Slope	Steam Output @600, 450, or 150 psig c_1 = Intercept d_1 = Slope	Steam Output @ [illegible] psig c_2 = Intercept d_2 = Slope	Hot Water @ 140°F c_3 = Intercept d_3 = Slope
Advanced Open Cycle Gas Turbine with Coal Derived Residual Fuel	a: 0.17246 b: 0.82589	c_1: 0.23885 d_1: 0.75893	c_2: 0.23885 d_2: 0.75893	(1)
Advanced Open Cycle Gas Turbine with Integrated Gasifier	(2)	(2)	(2)	(2)
Advanced Open Cycle Gas Turbine with AFB	a: 0.32811 b: 0.67296	c_1: 0.38303 d_1: 0.61815	c_2: 0.38303 d_2: 0.61815	(1)
Advanced Open Cycle Gas Turbine with PFB	a: 0.32748 b: 0.67296	c_1: 0.40630 d_1: 0.59440	c_2: 0.40630 d_2: 0.59440	(1)
Closed Cycle Gas Turbine with AFB	a: 0.02421 b: 0.97406	c_1: 0.03133 d_1: 0.96643	c_2: 0.02421 d_2: 0.97406	c_3: 0.03418 d_3: 0.96338
Molten Carbonate Fuel Cell with Coal Derived Distillate Fuel	a: 0.0 b: 0.97581	c_1: 0.0 d_1: 0.96252	c_2: 0.0 d_2: 0.97781	c_3: 0.0 d_3: 0.96114
Molten Carbonate Fuel Cell with Integrated Gasifier	(3)	(3)	(3)	(3)
Advanced Open Cycle Gas Turbine Subsystem for Combined Cycle	(2)	(2)	(2)	(2)

(1) All the reject heat can be recovered in the form of steam, so no hot water produced directly.
(2) Use the part-load equations for the Advanced Open Cycle Gas Turbine with Coal Derived Residual fuel.
(3) Use the part-load equations for the Molten Carbonate Fuel Cell with Coal Derived Distillate fuel.

b) Part Load Equations for the AFB and PFB Furnace Subsystems

Steam System Type \ Product	Fuel Input a = Intercept b = Slope
AFB Furnace Subsystem	a: 0.0 b: 0.99434
PFB Furnace Subsystem	a: 0.00397 b: 0.99612

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electricity, and the input desired is steam. In the case of gas turbine generators with heat recovery boilers (e.g., the advanced systems), the output specified is electricity (the primary output). The technology model then calculates the amount of required fuel (coal, oil or natural gas), and also the implied levels of the secondary outputs (hot water and the different types of steam). For the PFB furnace systems, the primary output is steam, and the secondary output is electricity. For each energy conversion system, the steps for deriving the fuel input or the secondary outputs are in the form of linear equations. These are generally referred to as Input-Output (I-O) equations.

The basic ingredients used in deriving the input-output equations are the full-load performance coefficients, and the part-load performance approximations. In order to utilize the full-load performance coefficients for the steam and hot water outputs, they must be adjusted to take account of the energy contained in the feedwater. NASA/LeRC provided us with the required feedwater enthalpy for the hot water and for each type of steam. From these we derived the conversion factors which are displayed in Table IV-5. The product of the original full-load coefficient and the corresponding conversion factor gives the adjusted full-load coefficient. The use of the conversion factors, the full-load performance coefficients, and the part-load performance approximations is illustrated by working through an example using the advanced closed cycle gas turbine-AFB. The performance data for this system is shown in Table IV-3.

C. Technology Modeling — An Illustrative Example

This example illustrates how the performance data for each energy conversion system is used to derive its input-output equations. The advanced closed cycle turbine-AFB is used in this example because it has

Table IV-5

Conversion Factors for Steam and Hot Water Outputs

Steam Pressure or Hot Water Temperature	Enthalpy of Steam or Hot Water, h_p	Enthalpy of Feed Water, h_w	Conversion Factor $\frac{hp}{hp-hw}$
600 psig	1203.0	220	1.224
450 psig	1204.5	220	1.223
150 psig	1195.5	108	1.099
50 psig	1179.7	108	1.101
Hot Water @140°F	106.0	38	1.543

one of the widest ranges of outputs; it may be operated to cogenerate electricity, hot water, and steam at 600 psig, 450 psig, 150 psig, and 50 psig. We make the example elaborate enough to consider all these outputs, although in a practical application only one or two steam qualities may be required. We shall first consider the case where only a single unit is installed: after that, we shall then discuss the problems introduced when multiple units of an energy conversion system are installed. A summary of the results from this example is given at the end in Table IV-6.

1. Parameters for the Example

The parameters for the example are:

- Energy conversion system: advanced closed cycle gas turbine-AFB.
- Fuel type: Illinois No. 6 bituminous coal.
- Size: 10 MW.
- Level of operation: 75 percent of full-load rating.
- Minimum electrical output constraint: 25 percent of full-load rating.
- Cogeneration of electricity and steam at 600 psig, 450 psig, 150 psig, 50 psig, and hot water.

2. Primary Output

The equation that relates a specified level of primary output with the implied output requirements is:

$$\begin{pmatrix}\text{Required}\\\text{Input}\end{pmatrix} = \frac{\begin{pmatrix}\text{Specified Level}\\\text{of Primary Output}\end{pmatrix}}{\begin{pmatrix}\text{Efficiency When Producing}\\\text{Primary Output at Full Load}\end{pmatrix}} \times \begin{bmatrix}\text{Scale Factor to}\\\text{Ensure Consistency}\\\text{in the Units of}\\\text{Measurement}\end{bmatrix} \times \begin{bmatrix}\text{Correction for Operation}\\\text{at Part Load}\end{bmatrix}$$

For our example, specified output is .75 x 10 MW = 7.5 MW. Efficiency at full load is given in Table IV-3 as .230. The part-load correction factor is linear with respect to the level of operation (i.e., in the form: a + b x (level of operation)). Table IV-4a gives 0.02421 and 0.97406 for the intercept and slope, respectively. The level of operation in this case is .75 (= 75 percent). Finally, since we want to find fuel input in Btu units, we have to use the conversion 1 MW = 3.413 x 10^6 Btu/hr to obtain consistent units.* Substituting the values into our equation, we get:

$$\begin{pmatrix}\text{Required Input}\\ \text{MBtu/hr Fuel}\end{pmatrix} = \underbrace{\left[\frac{(10\ \text{MW})\left(3.413\ \frac{\text{MBtu/hr}}{\text{MW}}\right)}{(.230)}\right]}_{\text{Required input at full load}} \underbrace{\left[.02421 + (.97406 \times .75)\right]}_{\text{Part-load correction}}$$

$$= 3.5926 + 14.4542 \times \underbrace{(7.5)}_{\text{Level of primary output}}$$

$$= 112.0\ \text{MBtu/hr.}$$

Note that the part-load correction factor for fuel input when operating the turbine at 75 percent of capacity is .7548. At full-load operation, the part-load approximation gives .02421 + .97406 x 1 = .9983 as the correction. This figure is not exactly equal to one, as one would expect. This is because the approximation was derived by minimizing the sum of the squared deviations from the sample points. Thus the line

---

*We use the notation MBtu for 10^6 x Btu.

obtained overshoots at some points and undershoots at others, but it is the line that is closest to all the sample points.

The relationship between input fuel and the output of electricity can be plotted on a straight line as shown in Figure IV-1. At 75 percent of capacity, efficiency is about .229, which is around 99 percent of the full-load efficiency. The efficiency drops to about .215 when operating at 25 percent of capacity. This is about 93 percent of full-load efficiency. All the input-output relationships in our technology model are of this linear form.

3. Secondary Outputs

Given the specified level of the primary output, the maximum amount that can be produced of each type of secondary output is:

$$\begin{pmatrix}\text{Output of}\\ \text{Secondary Output}\end{pmatrix} = \begin{bmatrix}\text{Fraction of Input Energy that}\\ \text{May be Used to Satisfy Output}\\ \text{of Type of Secondary Output}\\ \text{at Full Load}\end{bmatrix}$$

$$\times \begin{pmatrix}\text{Adjustment for}\\ \text{Feedwater Energy}\end{pmatrix} \times \begin{pmatrix}\text{Required Input Energy}\\ \text{at Full Load}\end{pmatrix}$$

$$\times \begin{pmatrix}\text{Part-Load Correction for}\\ \text{Type of Secondary Output}\end{pmatrix}$$

Note that since input energy is determined by the primary output, this formulation also gives a simple relationship between the primary output and the secondary outputs. For our example, the secondary outputs are steam at 600 psig, 450 psig, 150 psig, and 50 psig, as well as hot water at 140°F. The fraction of input energy that may be used to satisfy the output of each type of secondary output at full load are given in the full-load section of

Figure IV-1

Input-Output Relation Between Fuel Input

and Electricity Output for the Closed Cycle Gas Turbine-AFB

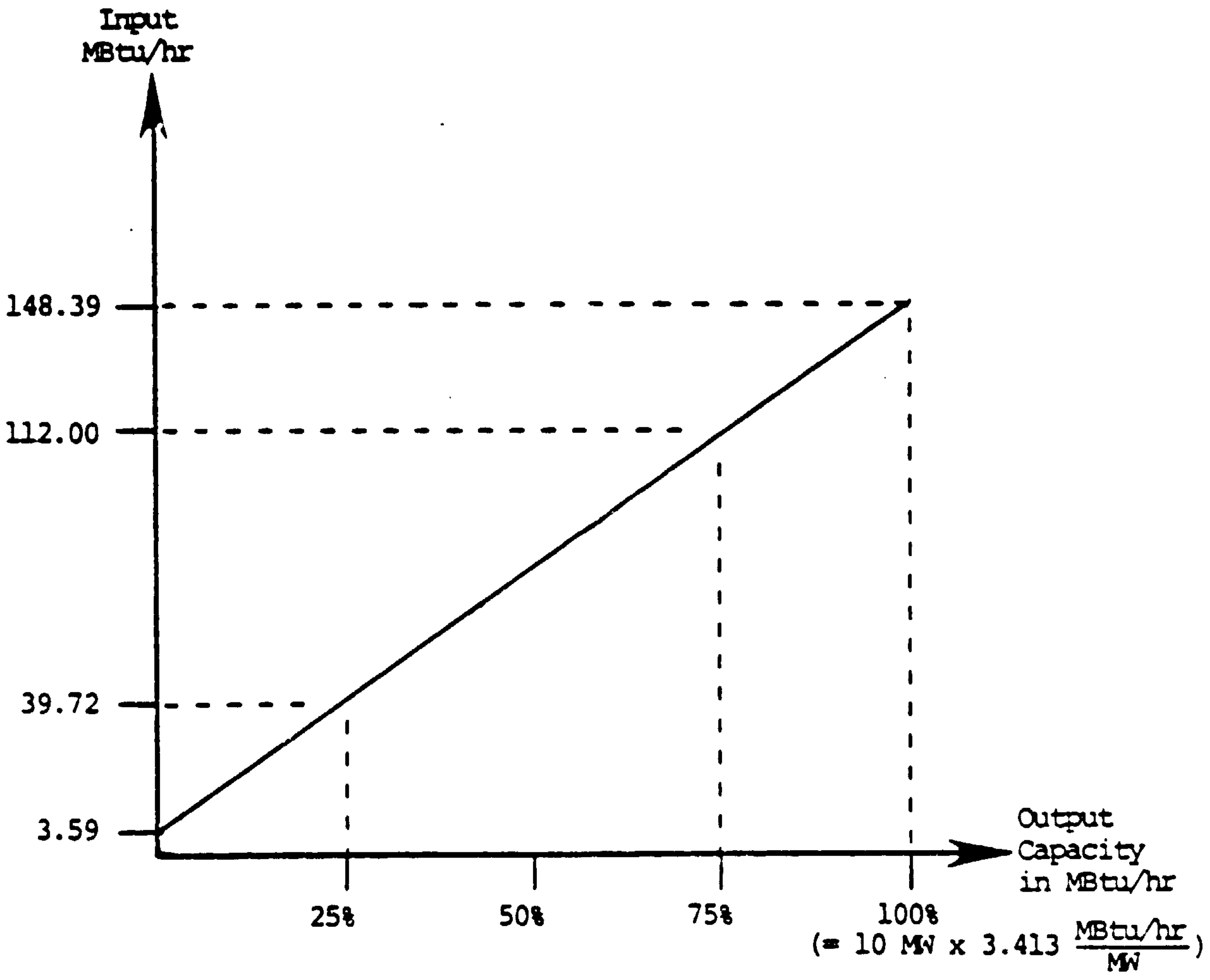


Table IV-3. The last column in Table IV-5 gives the factors used to account for the feedwater energy. The slope and intercept terms to be used in the part-load equation are given in Table IV-4a for each type of secondary output. Substitution of the necessary values into the output equation gives:

$$
\begin{aligned}
(\text{Output of 600 psig Steam}) &= (.322)(1.224)(148.3913) \\
&\quad \times (.03133 + .96643 \times .75) \\
&= \underbrace{(58.4852)}_{\text{Output at full load}}\underbrace{(.7562)}_{\text{Correction for part load}} \\
&= 44.2 \text{ MBtu/hr}
\end{aligned}
$$

To highlight the direct relationship between secondary outputs and the primary output, we could have used the expression for required full-load input in carrying out the above calculation. This gives

$$
\begin{aligned}
&(.322)(1.224)\underbrace{\left[\frac{(10\text{ MW})\ \left(3.413\ \frac{\text{MBtu/hr}}{\text{MW}}\right)}{.230}\right]}_{\text{Required full-load input}}(.03133 + .96643 \times .75) \\
&= 1.8323 + 5.6514 \times \underbrace{(7.5)}_{\text{Primary output 7.5 MW}} \\
&= 44.2 \text{ MBtu/hr}
\end{aligned}
$$

Since the required full-load input has already been calculated as 148.3913, we shall just substitute it into the subsequent calculations without trying to show the linear relationship between each secondary output and the primary output. However, this is the relationship that will be used in the calculations in the section on multiple units.

$$(\text{Output of 450 psig Steam}) = [(.027)(1.223)(148.3913)] \times [.03133 + .96643 \times .75]$$
$$= (4.9000)(.7562)$$
$$= 3.7 \text{ MBtu/hr}$$

$$(\text{Output of 150 psig Steam}) = [(.064)(1.099)(148.3913)] \times [.03133 + .96643 \times .75]$$
$$= (10.437)(.7562)$$
$$= 7.9 \text{ MBtu/hr}$$

$$(\text{Ouput of 50 psig Steam}) = [(.044)(1.101)(148.3913)] \times [.02421 + .97406 \times .75]$$
$$= (7.1887)(.7548)$$
$$= 5.4 \text{ MBtu/hr}$$

$$(\text{Output of Hot Water @}140^{\circ}\text{F}) = [(.137)(1.543)(148.3913)] \times [.03418 + .96338 \times .75]$$
$$= (31.3686)(.7567)$$
$$= 23.7 \text{ MBtu/hr}$$

Note that in the case of the PFB furnace system, the primary output is the steam and electricity is the secondary output. While the roles of steam and electricity are reversed in the equations, the modeling principle is the same. A secondary output is computed as a fraction of the full-load input requirement, which is determined by the primary output.

To run the energy conversion system in this example to produce only electricity, 600 psig steam and 450 psig steam, we assume the heat available at 150 and 50 psig can be recovered as hot water giving a total hot water output of:

$$[7.9 + 5.4 + 23.7]\ \text{MBtu/hr} = 37.0\ \text{MBtu/hr}$$

from 150 psig steam	from 50 psig steam	original hot water output

In general, we make the assumption that steam at higher pressure may be throttled without extra cost and without energy loss to steam at lower pressure or to hot water.

4. Installation of Multiple Units

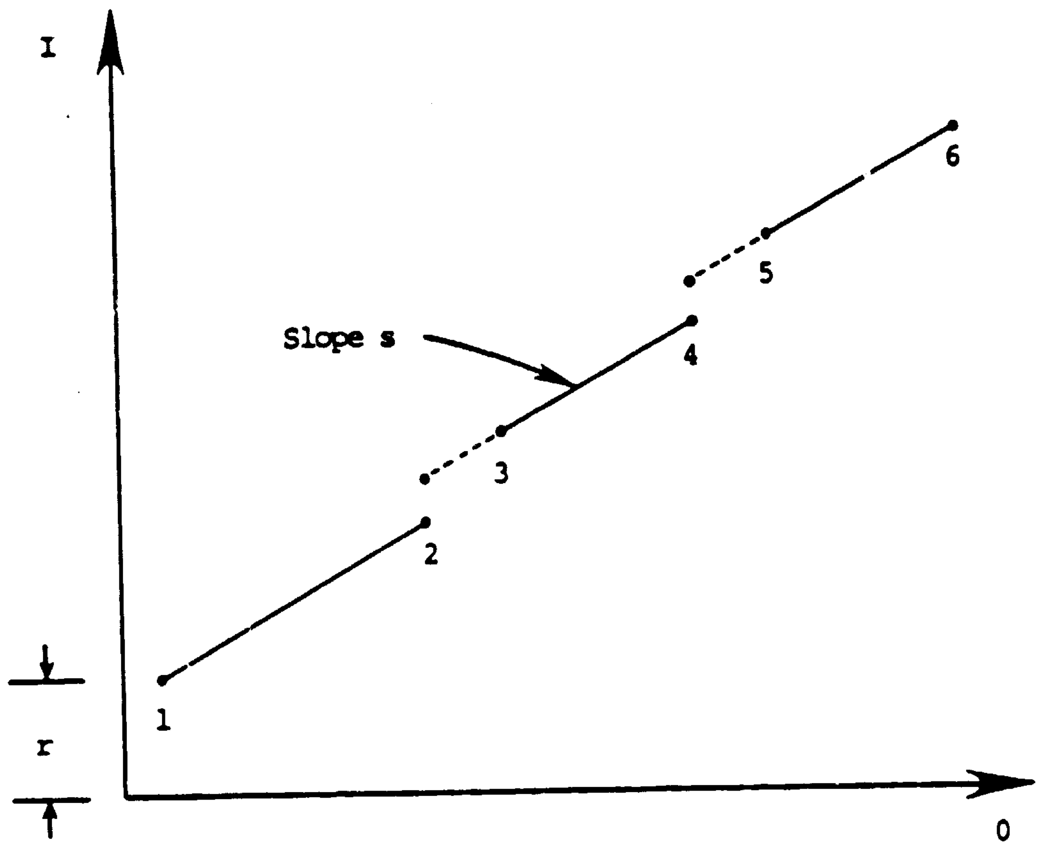
Industrial power systems are often designed to incorporate multiple units of equipment. Thus, for example, 30 MW of electric capacity might be provided using two turbine units rated at 15 MW each, or three at 10 MW each, or some other combination. In the case where steam turbines-generators are used, the plant may also incorporate two or more boiler units to provide the required steam output.

Multiple unit installations are commonly employed for reliability and maintenance scheduling purposes. That is, in a multiple unit installation, one may be able to rotate individual units in and out of service for repair or routine maintenance, leaving the other units to accommodate concurrent service demands.

A detailed model of a multiple unit installation can be developed by combining the models for several individual units. Figure IV-2, for example, depicts the input-output (I-O) relationship for a three-unit installation as the combination of the I-O relationships for three individual units. At Point 1 the first unit is on and operating at the minimum output level. Increasing the input to this first unit gradually brings it up to rated capacity at Point 2. To increase output beyond Point 2 requires turning on the second unit, which, when operated at minimum

Figure IV-2

Input-Output Relationship for Multi-Unit Plant (Exact)



output, brings the total plant output to Point 3. Operation between Points 2 and 3 can be achieved by backing off the first unit while keeping the second unit on, as shown on the dashed line extending downward from Point 3; an analogous procedure would provide the operation between Points 4 and 5, after the third unit has been turned on. To reach maximum plant output, all three units must be on and operating at rated capacity (Point 6).

The principal problem with the modeling approach described above is that it substantially increases the number of integer variables in the overall problem. This occurs because one must use integer variables to keep track of whether a given device is on or off. This proliferation of integer variables substantially increases the model solution time. There is also an element of uncertainty as to when each additional unit will be brought on line since operating practices will tend to vary from company to company.

An alternative approach is to develop an I-O relationship applicable to the whole plant, rather than one for each unit. The I-O equation for a single unit as shown in Figure IV-3a is of the form

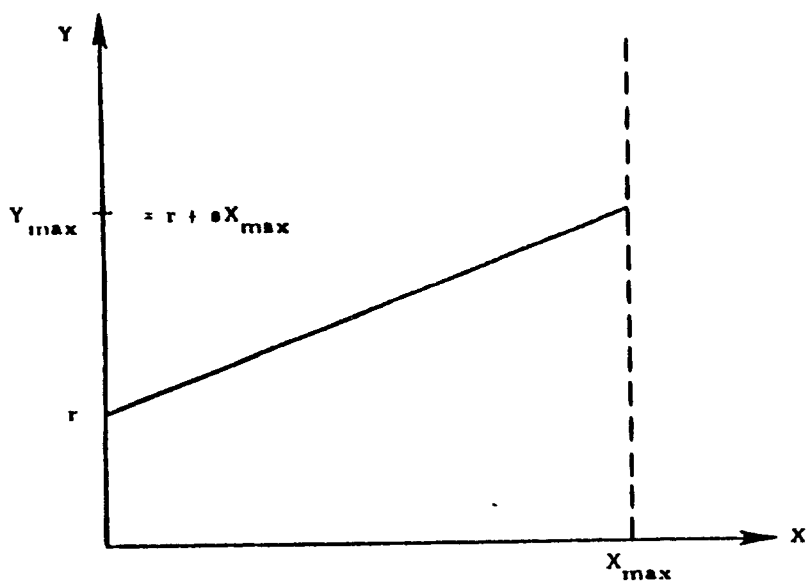
$$Y = r + sX$$

where Y is required input, and X is output. The intercept is r and s is the slope. For the previously mentioned example case of the AFB closed cycle gas turbine,

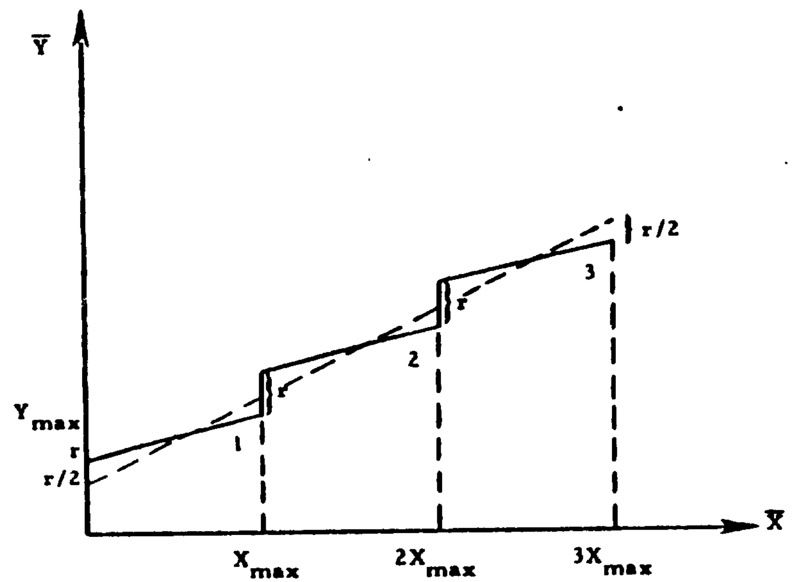
$$r = \left(\frac{\text{power-full load}}{\eta_E \text{ - full load}}\right) a_{\text{part load}} \times 0.410 = 3.5926$$

Figure IV-3

a) Single Unit



b) Multiple Units



and $s = \left(\frac{b_{\text{part load}}}{\eta_E - \text{full load}}\right) \times 3.410 = 14.4542$

If we assume that each unit is operated to capacity before an additional unit is brought on line, then the I-O relationship for the whole plant may be represented by a staircase with steps of height r at intervals of X_{max} (capacity output of one unit), as shown in Figure IV-3b.

If N identical units are installed in the plant, then the overall slope of the staircase function is $N(r + sX_{max})/(N \times X_{max})$. Letting $\bar{X}$ be the plant output, and $\bar{Y}$ the corresponding required input, then a likely approximation candidate for the overall plant I-O relationship is the linear equation

$$\bar{Y} = qr + (s + r/X_{max})\bar{X}.$$

Setting $q = 1/2$ gives a line which just bisects all the steps and all the slope segments. Since the line will be too high half of the time and too low the other half, with equal deviations, it is the "fairest" approximation. The cummulative input requirement figured by sampling this line with random values of the output $\bar{X}$ will equal (in the probablistic sense) the cummulative input figures from the true function. Therefore, $q = 1/2$ is the value used in the model.

The treatment of multiple devices is greatly complicated when there are secondary outputs. In this case there are constraint equations describing the relation between the outputs in addition to the fuel equation:

$$Y = \sum_i r_i + \sum_i w_i X_i$$

$$v_k = h_k Y_i + \sum_i w_{ki} X_i \leq 0$$

In the simplest case, let Z denote a second output, with the constraints

$$0 \leq X \leq X_{max}, \quad 0 \leq Z \leq v + wX$$

As shown in Figure IV-4a, for multiple devices, the maximum constraints are pushed back according to the number of devices:

$$0 \leq \bar{Z} \leq N \times (v + w\bar{X}),$$

$$0 \leq X \leq N \times \bar{X}_{max}$$

Introducing a minimum constraint, $X_{min} \leq X$, complicates the picture. As shown in Figure IV-4b, the X_{min} propogates into a staircase-shaped boundary. Since the multiple-device constraints can only be linear equations, an approximation to this staircase is needed. The simplest approach would be simply to extend the minimum constraint unchanged to the N-device model and ignore the effects, as shown in Figure IV-4c.

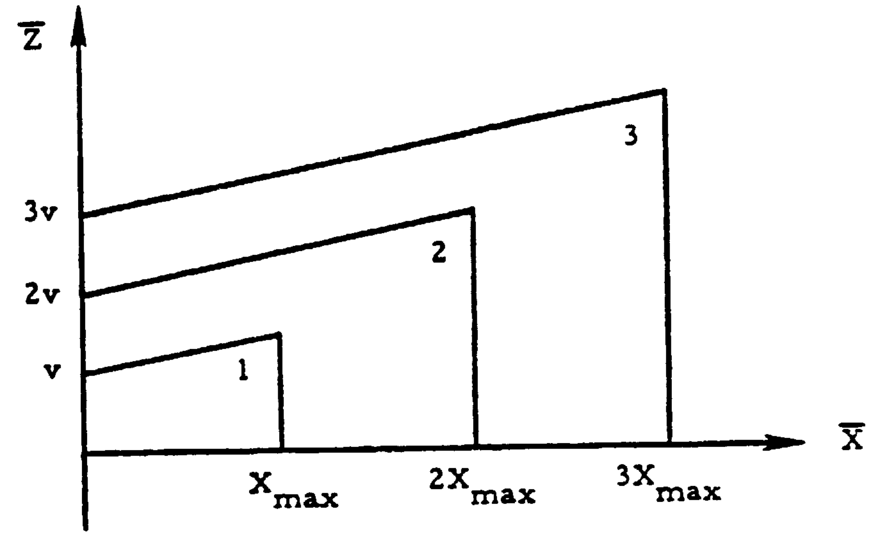
A more satisfying approach would be to replace the minimum constraint on $\bar{X}$ by a joint $\bar{Z}$-$\bar{X}$ constraint line which approximates the staircase. Figure IV-4b shows such a line; its equation is:

$$\bar{Z} \leq (-v/2) + X \times (w + v/\bar{X}_{min}).$$

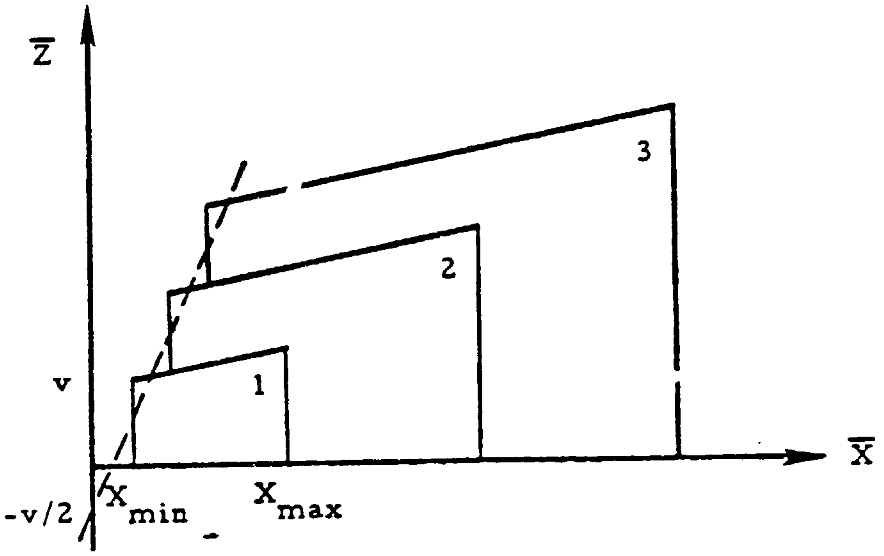
Unfortunately this treatment greatly complicates the model, so the simple approximation (c) is used with suitable caution against operating in the high $\bar{Z}$, low $\bar{X}$ region.

Figure IV-4

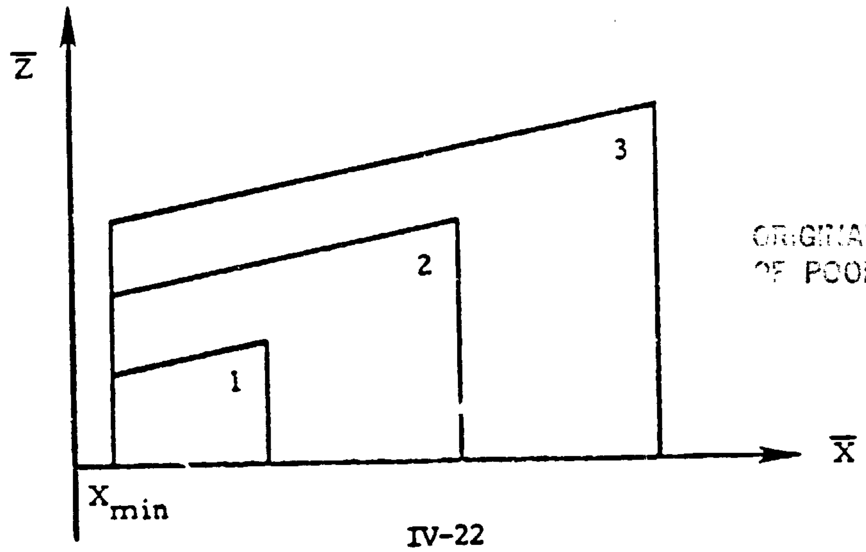
a)



b)



c)



The fuel input equation for a device with a secondary output is straightforward to model as long as the joint output constraints converge on the origin, as shown in Figure IV-5:

$$0 \leq X \leq X_{max};\ 0 \leq Z \leq wX;\ Y = r + sX + tZ.$$

The extension of these equations to multiple devices gives the stepped-surface input function of Figure IV-5. In this situation, the general guideline of bisecting the steps can readily be applied to yield the approximation:

$$\overline{Y} = r/2 + \overline{X} \times (s + r/X_{max}) + \overline{Z} \times t,$$

for

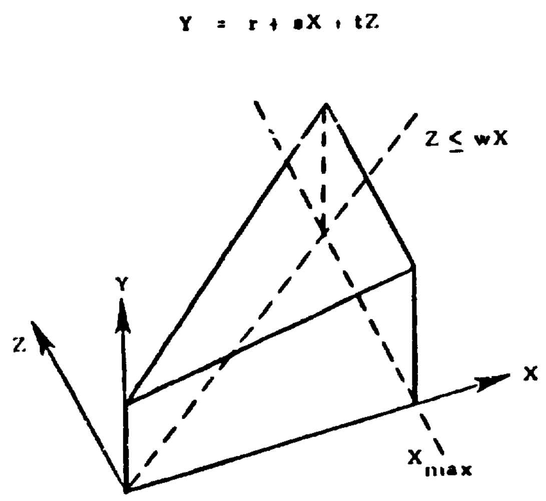
$$0 \leq \overline{X} \leq N \times X_{max},\ 0 \leq \overline{Z} \leq w\overline{X}.$$

When the output constraints enclose the origin rather than converge on it, as shown in Figure IV-6a, then the nature of a good I-O approximation becomes less obvious. The extension of this type of single device to multiple operation yields the input surface in Figure IV-6b, with concentric steps away from the origin. The continuous analog of this surface would be a quadrant of a funnel, which cannot be approximated well over its whole surface by a single plane.

For devices of this type, the approximation used is based on two of the fundamental characteristics of the true surface. The primary condition applied is to preserve the overall slope along the line from the origin to the maximum joint output. This provides the best fit for operation in the region of maximum fuel utilization. The secondary condition is to preserve the contours of constant input. This degrades the fit along the X and Z

Figure IV-5

a)



b)

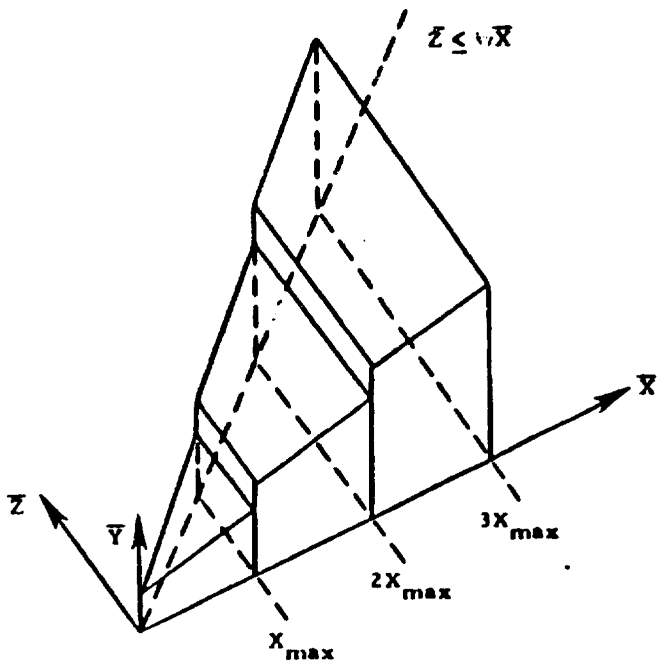
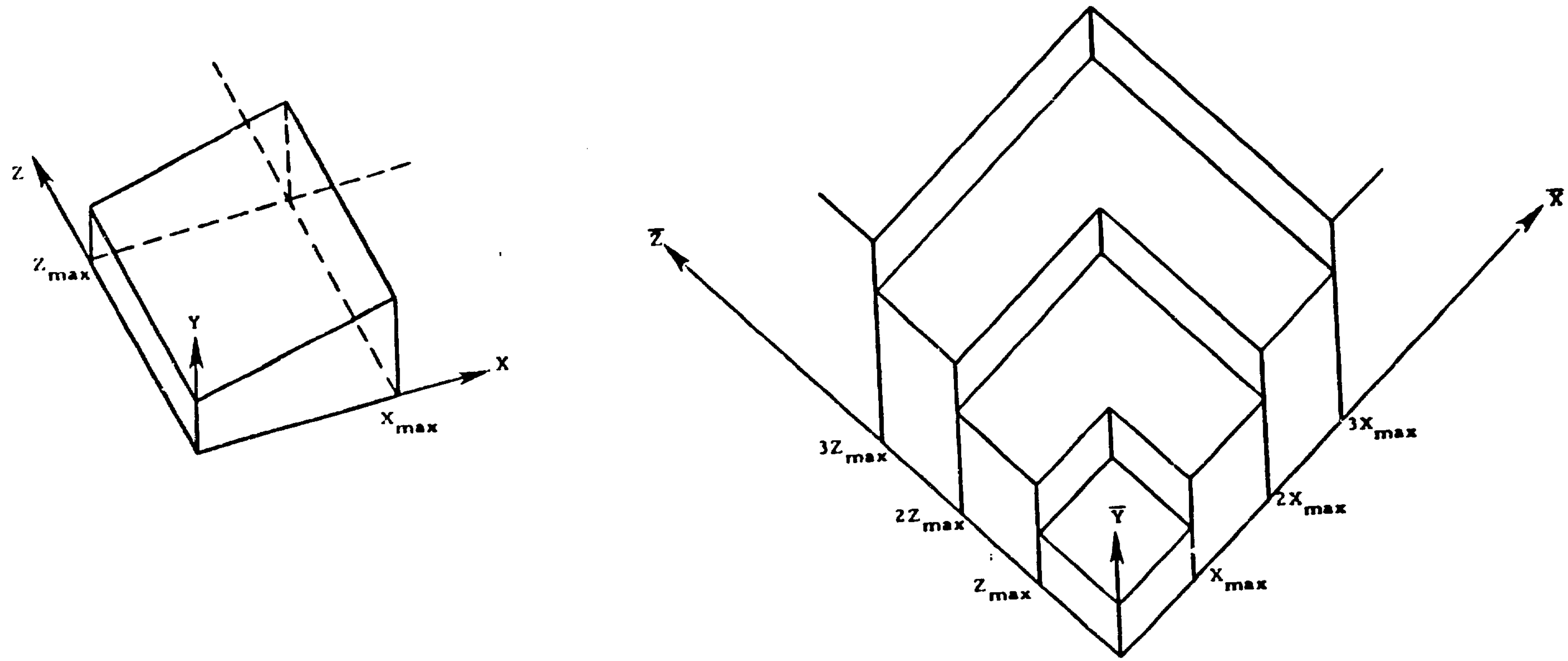


Figure IV-6

a)

b)



axes "equally." (If the usage of the model warranted, this could be replaced by a condition which would preferentially fit one edge at the expense of the other.) These conditions yield the following equation:

$$\bar{Y} = r/2 + (\bar{X} \times s + \bar{Z} \times t) \times [1 + r/(sX_{max} + tZ_{max})].$$

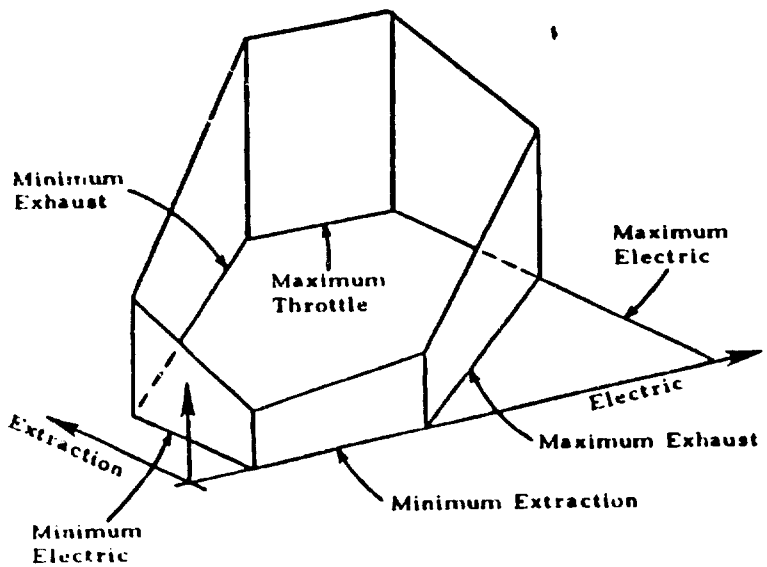
This formulation is the basis for all the multiple-device models used in this study, with suitable choices for the maximum values in the aggregation correction term. For example, for boilers there is only one output, so Z is dropped and X_{max} represents the rated steam capacity. For cogeneration devices, the input is a function only of one output, so again Z is dropped from the equation. For steam turbines, the two outputs are electricity, E, and extracted steam, X, with a multitude of joint constraints as shown in Figure IV-7. In this case, the "combined maximum" point used to set the primary condition on the overall slope was taken to be the intersection of the maximum throttle line with a line from the origin to the intersection of the maximum electric constraint with the minimum exhaust constraint.

5. Example — Continued

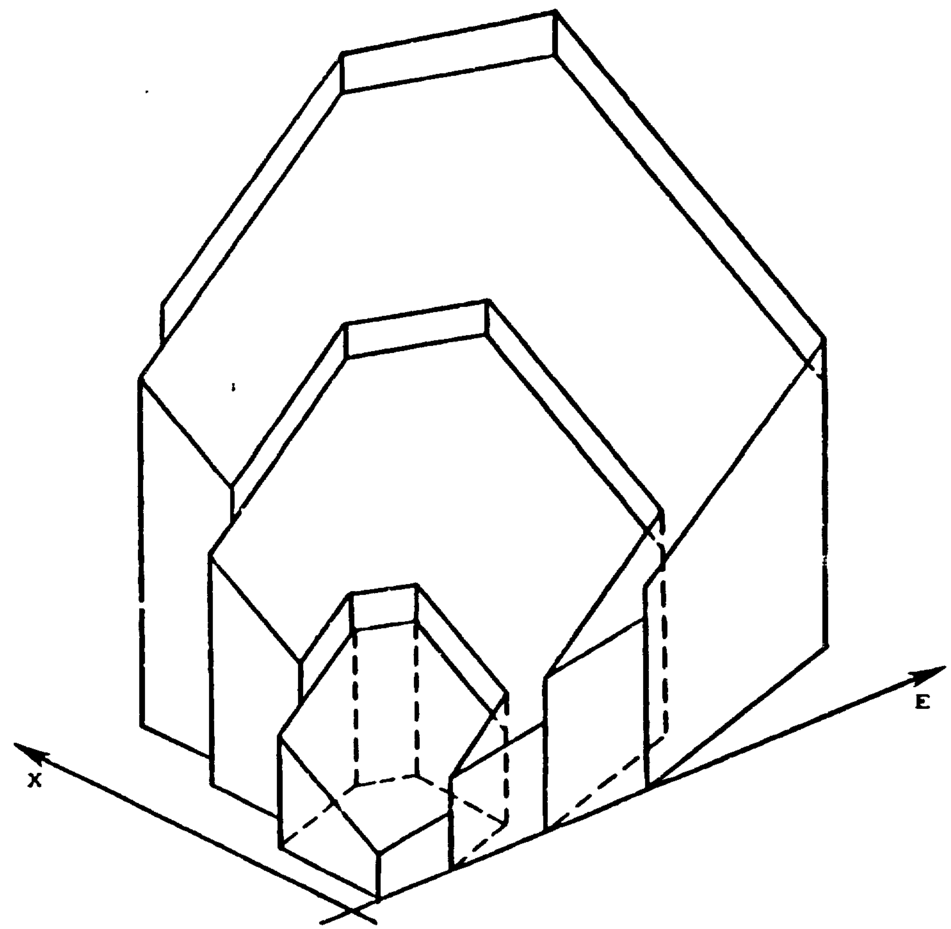
We extend our illustrative example based on the advanced closed cycle gas turbine-AFB by assuming that five turbines, instead of one, have been installed in the plant. In this context, operation at 75 percent capacity applies to total plant capacity which is 50 MW. The multiple device fuel input equation, with Z dropped, becomes $\bar{Y} = r/2 + (s + r/X_{max})\bar{X}$. The equation for the secondary outputs remains: $\bar{Z} \leq N \times v + w \times \bar{X}$. Recall that $r = 3.5926$ and $s = 14.4542$.

Figure IV-7

a) Single Device Steam Input Function



b) Multiple Devices



Substitution of the necessary values into the fuel equation gives

$$\begin{pmatrix}\text{Input Fuel}\\ \text{MBtu/hr}\end{pmatrix} = .5(3.5926) + [14.4542 + 3.5926/10](50 \times .75)$$

$$= 557.3 \text{ MBtu/hr}.$$

For the output of the 600 psig steam, recall that the values of v and w were calculated as $v = 1.8323$, $w = 5.6514$, and of course $N = 5$. The $\bar{Z}$ equation thus gives:

$$(\text{Output of 600 psig steam}) \leq 5 \times (1.8323) + (5.6514) \times (37.5)$$

$$= 221.089 \text{ MBtu/hr}.$$

Similar calculations give the level of the remaining secondary outputs as:

450 psig steam	=	18.53 MBtu/hr
150 psig steam	=	39.45 MBtu/hr
50 psig steam	=	27.13 MBtu/hr
Hot Water at $140^{\circ}F$	=	118.42 MBtu/hr.

Note that the values derived from the overall plant I-O equations are not necessarily equal to five times the corresponding values derived from the single device I-O equations. This is the price paid for reducing the size and complexity of the problem by taking our modeling approach. Table IV-6 presents the values obtained from the calculations in our example, together with the energy inputs from the feedwater. These energy values are also converted to mass flows, so that we can get an overview of both the energy and mass balances in the system.

Table IV-6

Summary of Mass and Energy Flows for Example Case:

Closed Cycle Gas Turbine-AFB Operating at 75 Percent

of Rated Capacity

	Single Device (10 MW)		Multiple Units (5) (50 MW)	
	MBtu/hr	Klb/hr	MBtu/hr	klb/hr
INPUTS				
Fuel	112.00	—	557.30	—
Feedwater				
@220 Btu/lb	8.76	39.84	43.82	199.16
@108 Btu/lb	1.21	11.20	6.05	56.01
@ 38 Btu/lb	8.33	219.26	41.67	1,096.48
TOTAL	130.30	270.30	648.84	1,351.65
OUTPUTS				
Electricity	25.60	—	127.99	—
Steam				
@600 psig (h=1203)	44.22	36.76	221.09	183.78
@450 psig (h=1204.5)	3.71	3.08	18.53	15.38
@150 psig (h=1195.5)	7.89	6.60	39.46	33.01
@ 50 psig (h=1179.7)	5.43	4.60	27.13	23.00
Hot Water @140°F (h=108)	23.68	219.26	118.42	1,096.48
TOTAL	110.53	270.30	552.62	1,351.65

V. COST CALCULATIONS

Cost calculations were carried out by closely following NASA/LeRC's "Groundrules for CTAS Economic Analysis" (GCEA).* The cost reported as the objective function of a run is the levelized annual cost as defined on page 11 of the GCEA. This is the constant revenue required each year to exactly cover all expenses. The expression used to calculate this cost is:

Levelized Annual Cost = Levelized Fixed Charges

+ Levelized Operating Costs

- Levelized revenues.

Levelized fixed charges apply to expenditure on equipment purchase, while levelized operating costs apply to fuel purchases, payments to utilities, and regular expenditures on operation and maintenance (O&M). In our context, the only revenue considered is that resulting from the sale of electricity to utilities by the industrial plant.

A detailed discussion of each of these components of levelized annual cost is given below. In carrying out the calculations, specific values have to be assumed for a number of parameters. Table V-1 lists these parameters and the value assigned to each. In all cases the values used are those supplied by NASA/LeRC. However, the computer programs that do the actual calculations are set up so any of these parameters may be set to any value for a run. Finally, all costs and revenues in the model are expressed in terms of 1978 dollars.

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*NASA/LeRC, "Groundrules for CTAS Economic Analysis".

Table V-1

Parameters Used in the Calculation Costs

Parameter	Symbol	Value
Cost of Capital	r	5.4%
Book Life of Equipment	n	30 years
Tax Life of Equipment	m	15 years
Combined Federal, State and Local Income Tax Rate	T	50%
Local Taxes and Insurance	I	3%
Investment Tax Credit	u	10%
Length of Construction Period	L	Varies With Type of Equipment (see Table IV-2)

A. Levelized Fixed Charges

For each equipment, the levelized fixed charge is that (constant) amount which, if realized each year throughout the life of the equipment, will exactly cover the net investment cost of that equipment. This cost is derived below using the closed cycle gas turbine-AFB as an example in the numerical calculations.

The general expression used is:

Levelized Fixed Charges = (Installed Cost) x (Fixed Charge Rate).

1. Installed Cost of Equipment

The installed cost of each equipment is part of our starting data. Cost data for the advanced equipment were supplied by NASA/LeRC, while those for the state-of-the-art equipment were updated from our precursor EPRI model. We assume that operations start in 1990, and installed cost is quoted with respect to this date, and in terms of 1978 dollars. Initial construction work on each equipment precedes this date by an amount of time equal to the length of the construction period. Table V-2 gives the estimated construction period for each type of equipment.

Each type of equipment is assumed to have a book life of 30 years. A zero real rate of escalation for equipment prices is also assumed. This means that equipment prices will increase at a rate comparable to the general inflation rate.

Since the installed cost data is independent of the fixed charge rate (FCR), it will not be used in the calculation illustrating our approach. For the sake of simplicity, we take it to be unity. The FCR is calculated

Table V-2

Estimated Construction Times

(years)

Advanced Open Cycle Gas Turbine with Coal-Derived Residual Fuel	1.5
Advanced Open Cycle Gas Turbine with Integrated Gasifier	3.5
Advanced Open Cycle Gas Turbine with AFB	2.5
Advanced Open Cycle Gas Turbine with PFB	2.5
Closed Cycle Gas Turbine with AFB	2.5
Molten Carbonate Fuel Cell with Coal-Derived Distillate Fuel	1.5
Molten Carbonate Fuel Cell with Integrated Gasifier	3.5
State-Of-The-Art Open Cycle Gas Turbine with Petroleum Distillate Fuel	1.5
State-Of-The-Art High Speed Diesel	1.5
State-Of-The-Art Low Speed Diesel	1.5
Combined Cycle (Gas Turbine-Steam Turbine) with Coal-Derived Residual Fuel	2.5
Conventional Steam System with Residual Fuel	2.5
Steam System — Coal-Fired with SO_2 Scrubber	3.0
Steam System with AFB	3.0
Steam Turbine-Generator	2.0
Package Boilers	1.5

Source: NASA/LeRC for all except last two. Burns and Roe, Inc. for the last two.

by taking account of the cost of capital,* the capital recovery factor, the cost of capital during construction, the investment tax credit, and depreciation treatment. Each of these components is discussed below.

Cost of capital (r) at zero percent inflation. The cost of capital is calculated by taking account of the various methods used in financing the total debt, and the cost associated with each. For a dollar of investment, the expression used is:

$$r = (1 - T) f_D i_D + \sum_{k \neq D} f_k i_k$$

where
r = cost of capital
f_D = fraction of debt capital
i_D = cost of debt
f_k = methods of financing, other than debt, e.g., equity capital
i_k = costs of other methods of financing
T = tax rate.

The above expression gives the after-tax cost of capital, assuming zero inflation. For the purposes of the ACTEOS study, a value of 5.4 percent was set by NASA/LeRC for the after-tax cost of capital, r.

Capital recovery or annualization factor [A(r,n)]. This is the equivalent annual cost of an initial investment. It depends on the rate of discount, which has been calculated above as the cost of capital, r, and the book life of the equipment, n. The formula used is:

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*The cost of capital as used here should be distinguished from the price paid for a piece of equipment -- the installed cost. It is an interest (or discount) rate; the price paid for the use of funds.

$$A(r,n) = \frac{r(1 + r)^n}{(1 + r)^n - 1}$$

for $r = .054$ and $n = 30$, $A(r,n) = .068047$.

Cost of capital during construction (CCDC). Periodic progress payments must usually be made during the construction period. However, the base period for the investment cost estimate is the date of initial operation. The existence of progress payments in advance of project completion thus implies we must add to the installed equipment cost the value of the returns that could have been earned on the capital (funds) tied up as progress payments. It is clear that this will depend on the length of the construction period for each equipment. It will also depend on contractual arrangements which may vary with a host of different factors. We have assumed that the pattern of payments can be approximated by a single complete payment occurring two-thirds of the way through the construction period. Thus, the foregone interest income occurs only over the last third of the construction period. This assumption leads to:

$$CCDC = (1 + r)^{L/3} - 1,$$

where L is the length of the construction period. For the closed cycle gas turbine-AFB, $L = 2.5$, so

$$CCDC = (1 + r)^{2.5/3} - 1 = .04480.$$

Investment tax credit (ITC). The investment tax credit rate, u, is taken to be 10 percent. This may be applied to the price of the equipment as well as the cost of capital during construction giving:

$$
\begin{aligned}
ITC &= (u)(1 + CCDC) \\
&= (.1)(1 + .04480) \\
&= .10448.
\end{aligned}
$$

Depreciation (DEP). The sum-of-years' digits method is used, and the assumed tax life of each equipment, m, is 15 years. The depreciation formula is:

$$DEP = \frac{2[m - \frac{1}{A(r,m)}]}{m(m + 1)r} .$$

Using the expression for the capital recovery factor to calculate A(r,m), and substituting gives:

$$DEP = \frac{2[15 - \frac{1}{.098964}]}{15(15 + 1)(.054)} = .75546.$$

Fixed charge rate (FCR). We can now collect all the terms to arrive at the formula for the fixed charge rate.

$$FCR = \frac{[(1 + CCDC) - ITC - (T)(DEP)]A(r,n)}{(1 - T)} .$$

The division by (1 - T) makes it a before-tax charge. For the closed cycle gas turbine-AFB, this gives the value:

$$FCR = \frac{[(1 + .04480) - .10448 - (.5)(.75546)](.068047)}{(1 - .5)} = .07657 .$$

Finally, we add local taxes and insurance costs, which together are assumed to be 3 percent of the price of the equipment, to arrive at

$$FCR + .03 = .07657 + .03 = .1066.$$

The only aspect of the above calculation that is equipment dependent is the length of the construction period, which is used to compute the cost of capital during construction (CCDC). To perform the calculation for other equipment, the appropriate construction period is used by referring to Table V-2.

B. Levelized Operating Costs

1. Operation and Maintenance (Excluding Fuel)

Operation and maintenance (O&M) expense for the advanced energy conversion systems were supplied by NASA/LeRC. The expense was based on usage, or the output of the equipment (i.e., dollars per killowat-hour). The O&M estimates for the advanced systems can be found in the tables in Appendix A. For the state-of-the-art systems, O&M was computed as a fraction of the initial investment expense. These fractions were estimated for us by Burns and Roe, Inc., and are shown in Table V-3.

2. Fuel and Electricity Prices

Fuel and electricity prices were calculated for six geographic regions in the U.S. in which industrial plants are analyzed. Calculations were also made for national (average) prices for analysis at the national level. These calculations were based on the most recent Department of Energy forecast of regional and national prices for fuels and electricity as contained in the report Historical and Forecasted Energy Prices by DOE Region and Fuel Type for Three Macroeconomic Scenarios (DOE/EIA-0184/15), July 1979.

The DOE forecasts are in terms of 1980 dollars per million Btu (MBtu) and are provided, under each scenario, for the years 1977, 1985, 1990 and 1995. Forecasts of the growth rates of prices in the intervening periods

Table V-3

Annualized Operation and Maintenance Expense

for State-Of-The-Art Equipment

Equipment Category	Annualized O&M Expense as a Percent of Investment Expense
Small Dual-Fueled Package Boilers	2.5
Natural Gas-Fired Steam Generation Plants	1.5
Other Fossil-Fired Steam Generation Plants	2.5
Waste Fuel-Fired Steam Generation Plants	3.5 - 4.5*
Steam Turbine Generator Plants	2.5
Gas Turbine Generator Plants	2.5
Diesel Generator Plants	7.0**
Heat Recovery Steam Generator Systems	1.5

* Varies depending on type of waste fuel.

** Excludes cost of major overhaul, required after approximately 25,000 hours of operation of an estimated cost of 50 percent of acquisition cost.

Source: Burns and Roe Industrial Services Corporation.

are also given. We chose the prices and growth rates given under Scenario C, which is based on the assumption of a moderate growth in the Gross National Product over the forecast period. For use in this study, the price forecasts were adjusted to 1978 dollars.

Since the forecasts do not extend beyond the 1995 period, we have assumed that the predicted growth rates for the 1990-1995 period continue out to the year 2019 (covering the 30-year horizon of our model). The only exception is in one region where DOE forecasts a negative growth rate for electricity prices. The assumption of a negative growth rate for 30 years would clearly lead to absurd results, so for this case we simply take the growth rate to be zero. In all other cases a positive growth rate was forecasted.

The levelized price for each fuel and for electricity is calculated by multiplying the present value of expenses on each fuel or electricity by the annualization or capital recovery factor, $A(r,n)$.

The annualization factor, $A(r,n)$, was discussed under the treatment of levelized fixed charges. The present value of expenses on each fuel or on electricity is computed by taking the sum of the discounted expenses for each year over the 30-year period. The price in any year after 1990 is computed by using the growth rates. Expenditures on fuel and electricity are assumed to occur at the end of the year, and quantities purchased are constant from year to year.

Let F be the amount paid for fuel or electricity in 1990. For simplicity assume F is equal to 1. Then the present value of expenditure on fuel and electricity is calculated as:

$$PV(r,g,n) = \frac{1}{(1+r)} + \frac{(1+g)}{(1+r)^2} + \frac{(1+g)^2}{(1+r)^3} + \cdots + \frac{(1+g)^{n-1}}{(1+r)^n}$$

$$= \frac{1}{(1+r)} \sum_{t=0}^{n-1} \left(\frac{1+g}{1+r}\right)^t$$

$$= \frac{1-\left(\frac{1+g}{1+r}\right)^n}{(r-g)} \qquad r \neq g$$

where g = growth rate of prices, r = cost of capital or discount rate (= .054), and n = 30.

Levelized prices are then given as:

$$L(r,g,n) = PV(r,g,n) \cdot A(r,n) = \left[\frac{1-\left(\frac{1+g}{1+r}\right)^n}{r-g}\right] \cdot \left[\frac{r(1+r)^n}{(1+r)^n - 1}\right]$$

$$= \left[\frac{1-\left(\frac{1+g}{1+r}\right)^n}{r-g}\right] \cdot (.068047) \quad \text{for } r \neq g.$$

The value obtained for $L(r,g,n)$ is then converted from 1980 dollars to 1978 dollars by using the implicit GNP deflator.

3. Fuel Prices

The fuels used by the equipment in our model are: coal, gas, distillate oil and residual oil. The prices for coal derived distillate or

residual are assumed to be equal to the prices for petroleum- derived distillate or residual oil.

For the fuels named, application of the levelized cost procedure outlined above was direct and simple. Shown in Table V-4 are the levelized prices for the four fuels in each of the six regions as well as national average prices. In the case of electricity prices, however, extra work was required in order to apply the procedure.

4. Electricity Prices

The extra problems encountered in using the DOE forecasts for electricity prices result from the fact that the forecasts do not include separately stated prices for peak demand and energy, which is the way most utilities sell to their industrial customers. The method we have used to handle this problem is as follows.

In each region we have selected a representative utility and examined the tariff which typically is used for sales by that utility to an industrial customer. We have then calculated the relative proportions of total electricity cost attributable to peak demand charges and energy charges, respectively, for an industrial customer with a peak demand of 10 MW and an average monthly purchase of 5.76 million kWh (this corresponds to a load factor of 0.8). These proportions are then applied to the DOE prices for 1977 in order to develop estimates of the peak demand price and energy price in each region in 1977. Finally, we make the assumption that the peak demand price remains unchanged between 1977 and 2019, in real terms, so that any real price increase forecasted by DOE can be attributed to increases in the energy price components of the tariff alone.

Table V-4

Levelized Fuel Prices (1990-2019)

(in 1978 dollars per million Btu)

DOE Region/State	Coal	Residual Oil (Petroleum or Coal Derived)	Distillate Oil (Petroleum or Coal Derived)	Gas (Natural or Coal Derived)
2 (New York)	2.4093	5.4463	6.9123	6.5335
3 (Pennsylvania)	2.2784	5.5268	7.0741	6.5706
5 (Wisconsin)	2.0380	5.4231	6.8801	6.5648
6 (Texas)	2.0558	5.3812	6.8939	4.4404
9 (California)	2.6087	4.7724	6.3399	5.6758
10 (Washington)	2.1264	4.7939	6.3399	5.8057
United States	2.1152	5.3813	6.8387	5.2833

The assumption of zero real growth in the peak demand price is justified if the following items can be assumed: (1) the price for peak demand (kW) reflects the cost of generating capacity, and the price for energy (kWh) reflects fuel and other operating costs; (2) the cost of new additions to utility capacity experiences zero real escalation over the forecast period; and (3) any forecasted changes in the regional mix of generating capacity will be small or will not appreciably affect the average real cost of capacity. The first assumption should be true in theory although it may not always be practiced. The second assumption is consistent with the assumption we have made with respect to the capital cost of the industrial power equipment, and is also the assumption built into the DOE forecast during the 1985-1995 period. The third assumption is the weakest link in the chain but is not unreasonable.

a. Historical Peak Demand and Energy Prices

The representative utilities which we have used in each state/region are listed in Table V-5. In general, the utility shown is the largest in its state in terms of industrial electricity sales or is representative of the large utilities in that state. Also shown is the specific tariff and its issue date.

For each utility we have calculated the relative fraction of demand and energy charges that would be experienced by an industrial customer with a peak demand of 10 MW and a load factor of 0.8. If we let

D = peak demand in kW (D = 10,000 kW),

E = energy usage in kWh (E = 5.76 million kWh),

$C_D(D,E)$ = monthly peak demand cost for a customer with purchases D and E,

Table V-5

Representative Utilities Used in Each State/Region

DOE Region	State	Utility	Tariff	Date of Tariff
2	NY	Niagara Mohawk Power Corp.	SC3-PSC-207	07/08/78
3	PA	Philadelphia Electric Co.	HT	03/01/78
5	WI	Wisconsin Electric Power Co.	Cp-1	01/16/78
6	TX	Houston Lighting and Power Co.	LGS	05/01/76
9	CA	Southern California Edison Co.	A-7	01/13/77
10	WA	Washington Water Power Co.	25	04/15/78

Note: Table of tariffs extracted from the National Electric Rate Book (DOE).

$C_E(D,E)$ = monthly energy cost for a customer with purchases D and E,

C_O = monthly fixed cost, if any,

$f_D(D,E)$ = fraction of total cost which is the peak demand (kW) cost,

$f_E(D,E)$ = fraction of total cost which is the energy (kWh) cost,

then we have

$$(1) \quad f_D(D,E) = \frac{C_O + C_D(D,E)}{C_O + C_D(D,E) + C_E(D,E)}$$

$$(2) \quad f_E(D,E) = 1 - f_D(D,E)$$

The energy and peak demand prices in each region for 1977 are then, respectively, calculated according to

$$(3) \quad P_{E,1977} = (P_{1977})(f_E)\left(\frac{PDGNP_{1978}}{PDGNP_{1980}}\right)\left(\frac{3412}{10^6}\right) \quad (1978\ \$/kWh)$$

$$(4) \quad P_{D,1977} = (P_{1977})(f_D)\left(\frac{PDGNP_{1978}}{PDGNP_{1980}}\right)\left(\frac{3412}{10^6}\right) (720\ \text{hours})(0.8)$$

$$(1978\ \$/kW/month).$$

where P_{1977} is the DOE estimate for 1977, f_D and f_E were defined previously, the ratio of GNP price deflators converts 1980 dollars to 1978 dollars, the last ratio converts MBtu to kWh, and the product of 720 hours and 0.8 is the ratio between kWh and kW at 0.8 load factor.

b. Base Year (1990) Prices and Growth Rates

Given the assumption that the price of peak demand has a zero real escalation rate, then the 1990 price for peak demand and the 1977 price are identical. That is,

$$P_{D,1990} = P_{D,1977}.$$

Furthermore, the levelized peak demand price during the 1990-2019 period will also be the same. That is,

$$(5) \quad P^{*}_{D,1990} = P_{D,1990} = P_{D,1977} = P_{D,2019}$$

where p^{*}_{D} is the levelized peak demand price in 1978 dollars per kW.

We obtain the 1990 energy price, $P_{E,1990}$, by noting that

$$(6) \quad (P_{D,1990}) + (P_{E,1990})(720)(0.8) = (P_{1990})\left(\frac{PDGNP_{1978}}{PDGNP_{1980}}\right)\left(\frac{3412}{10^6}\right)(720)(0.8)$$

where P_{1990} is the DOE forecast for 1990.

The post-1990 growth rate, g', for the energy price is determined from the relationship

$$(7) \quad P_{D,2019} + (1 + g')^{30}(P_{E,1990})(720)(0.8)$$

$$= (1 + g)^{30}(P_{1990})\left(\frac{PDGNP_{1978}}{PDGNP_{1980}}\right)\left(\frac{3412}{10^6}\right)(720)(0.8)$$

where g is the DOE forecast for the growth rate in total electricity price beyond 1990.

We have already noted in the previous section that the levelized price for peak demand during the 1990-2019 period is

$$P^{*}_{D,1990} = P_{D,1990} = P_{D,1977}.$$

The levelized price for energy is given by

$$(8)\quad P^{*}_{E,1990} = P_{E,1990} \times L(r,g',n)$$

where g' is the post-1990 growth rate for energy (kWh) price as determined from (7).

c. Illustrative Example

To illustrate the procedures outlined above, we will carry out a sample calculation for DOE Region 9, using Tariff A-7 for Southern California Edison as shown in Table V-6.

D	=	10,000 kW	
E	=	$(0.8)(720)D$ = 5.6 million kWh	
C_O	=	0	
$C_D(D,E)$	=	\$9,350.00	(from the tariff)
$C_E(D,E)$	=	\$91,729.50	(from the tariff)
f_D	=	.0925	(from (1))
f_E	=	.9075	(from (2))
P_{1977}	=	\$10.70 per MBtu	(from DOE Report)
$PDGNP_{1978}$	=	1.508	(from DOE Report)
$PDGNP_{1980}$	=	1.715	(from DOE Report)
$P_{E,1977}$	=	\$0.02913 per kWh	(from (3))
$P_{D,1977}$	=	\$1.710 per kW	(from (4))

$$P^{*}_{D,1990} = P_{D,1990} = P_{D,1977} = \$1.710 \text{ per kW} \quad \text{(from (5))}$$

Table V-6

Department of Energy National Electric Rate Book

Tariff A-7 for Southern California Edison Co.

(partial copy)

Rate:

DEMAND CHARGE:

$260.00	for first	200	kW demand or less
$ 1.05 per kW	next	1,800	" "
0.90 " "	"	8,000	" "
0.75 " "	all additional		" "

ENERGY CHARGE:

First 150 kWh per kW demand -	
First 30,000 kWh	2.690¢ per kWh
Balance	2.015¢ " "
Next 150 kWh per kW demand	1.658¢ " "
All Additional kWh	1.320¢ " "

p_{1990} = \$11.43 per MBtu (from DOE Report)

$p_{E,1990}$ = \$0.03132 per kWh (from (6))

g = 0.0149 (from DOE Report)

g' = 0.01603 (from (7))

r = 0.054

n = 30

$L(r,g',n)$ = 1.197

$p^*_{E,1990}$ = \$0.03746 per kWh (from (8))

Thus, the levelized prices for electricity in DOE Region 9 (which includes the State of California), for the period 1990-2019, are

$p^*_{D,1990}$ = \$1.710 per kW

$p^*_{E,1990}$ = \$0.03746 per kWh

both expressed in 1978 dollars. Values for the other regions/states are provided in Table V-7.

d. Billing Demand

During months when an industrial customer reduces its purchases of electricity (i.e., low or zero demand periods), it is common for the utility to require the customer to continue to pay a sizeable demand charge in those months. The actual practice varies from utility to utility. For example, among the utilities listed in Table V-5, a payment ranging from 50 to 100 percent of the highest demand charge in the preceding 12 months is typical.

For the four industries we are examining, some have periods with demand falling as low as 65 to 75 percent. We have assumed, however, that

Table V-7

Regional Electricity Prices, 1990-2019 (Levelized)

(in 1978 dollars)

DOE Region/State	$P^*_{D,1990}$ ($/KW)	$P^*_{E,1990}$ ($/KWh)
2 (New York)	5.338	.02388
3 (Pennsylvania)	3.856	.02954
5 (Wisconsin)	4.249	.02763
6 (Texas)	1.790	.03591
9 (California)	1.710	.03746
10 (Washington)	0.000	.01410
United States**	2.431	.02992

** $f_E^{U.S.}$ = .8303 by averaging.

these low demand periods are interspersed throughout the year (i.e., nights, weekends, 2-3 week maintenance periods) so that the monthly demand for peak demand billing purposes is constant throughout the year.

e. Standby Capacity

We have assumed that standby capacity can be bought from the utility at the price of $2 per kW per month. This figure is consistent with the U.S. average peak demand price shown in Table V-7. That is, one would expect the standby charge to be something less than a utility's long run marginal cost for capacity — a figure which in theory is reflected in a utility's peak demand price.

C. Levelized Revenues

1. Buy-Back Price

We have assumed that electricity can be sold back to the utility at a price equal to 60 percent of the utility's selling price. In the notation of the previous sections, the levelized buy-back price is thus

$$P^*_{B,1990} = (0.60)(P^*_{1990}).$$

However, the model is built in such a way as to allow us to easily vary this rate from 0 to 100 percent of the utility's selling price.

2. Buy-Back Limits

Although in past years industrial generators of electricity have had the threat of regulation hanging over them if they engaged in sales of electricity, recent moves by FERC have sought to remove these inhibitions. Specifically, cogenerators, small power producers under 30 MW capacity, and facilities generating electricity from biomass would be exempted from most

state and federal rate regulation under rules recently proposed by FERC. Pending resolution of this issue, we have assumed that there are no limits on sales of excess power, except those limits imposed by the economics of the situation.

VI. INDUSTRIES ANALYZED IN THE MODEL

Data on four industries are included for analysis in the study. These are: newsprint, writing paper, chlorine, and petroleum refining. Energy demand data were received from NASA/JPL in the form of a load ratio/duration profile for each industry. These profiles were all constructed on the assumption that thermal and electric demands are in phase at all times.

A year is taken to consist of 8,760 hours. Although most of the industries operate for less hours, the load ratio/demand profile for each was scaled in such a way as to make their actual demands consistent with an 8,760 hour year. Annual operations in each industry, except petroleum refining, are broken down into three time periods. These correspond to the hours of peak, normal, and low production activity in the industry. Demand in the normal period was taken to be the annual average for the industry. The peak demand is generally about 10 percent more than that of the normal period. For the case of petroleum refining, there are four time periods instead of three.*

Tables VI-1 to VI-4 give the electric and thermal demands for each industry as calculated from its load ratio/duration profile. Our technology model has equipment capable of producing saturated steam at 50 psig, 150 psig, 300 psig, 450 psig, and 600 psig. It also has equipment in the form of boilers or heat recovery steam generators for producing high

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*It should be noted that the load ratio/duration for each industry is assumed to remain constant over the 30-year period covered by the study.

Table VI-1

Newsprint (SIC 2621)

Electric and Thermal Demands

Demands	Hours	Production (tons/day)	Electricity (MW)	50 psig Steam (10^6 Btu/hr)	Hot Water @ 140°F (10^6 Btu/hr)
Period 1	657.00	1320.0	77.0	260.70	162.80
Period 2	6876.60	1200.0	70.0	237.00	148.00
Period 3	1226.40	840.0	49.0	165.90	103.60

Table VI-2

Writing Paper, Bleached Kraft

Electric and Thermal Demands

Demands	Hours	Production (tons/day)	Electricity (MW)	50 psig Steam (10^6 Btu/hr)	Hot Water @ 140°F (10^6 Btu/hr)
Period 1	1314.00	1320.0	44.0	418.00	264.00
Period 2	6351.00	1200.0	40.0	380.00	240.00
Period 3	1095.00	1056.0	35.2	334.40	211.20

Table VI-3

Chlorine (SIC 2812)

Electric and Thermal Demands

Demands	Hours	Production (tons/day)	Electricity (MW)	50 psig Steam (10^6 Btu/hr)	150 psig Steam (10^6 Btu/hr)
Period 1	876.00	660.0	99.0	74.03	137.50
Period 2	4380.00	600.0	90.0	67.30	125.00
Period 3	3504.00	540.0	81.0	60.57	112.50

Table VI-4

Petroleum Refining (SIC 2911)

Electric and Thermal Demands

Demands	Hours	Production (10^3 barrels/day)	Electricity (MW)	50 psig Steam (10^6 Btu/hr)	150 psig Steam (10^6 Btu/hr)	450 psig Stea (10^6 Btu/hr)
Period 1	836.28	262.5	42.0	351.225	114.975	1555.050
Period 2	5414.89	250.0	40.0	334.500	109.500	1481.000
Period 3	2090.69	212.5	34.0	284.325	93.075	1258.850
Period 4	418.14	175.0	28.0	234.150	76.650	1036.700

for producing high pressure steam at 600 psig-750°F, 850 psig-825°F, and 1,450 psig-950°F. Whenever the type of process steam demanded in an industry does not exactly match one of these steam types, we make the assumption that the demand is for the next highest steam pressure in our model. This is consistent with our technological assumption that steam may be throttled to lower pressure steams or to hot water without any energy loss, and at no extra cost. Thus, for example, industrial demand for 30 psig steam is represented as demand for 50 psig steam in the model.

VII. OPTIMIZATION RESULTS

A. Overview

The original scope of the project was to simultaneously optimize the selection and operation of technologies within each of the state-of-the-art systems and advanced-systems groups of technologies as listed in Table II-1. Thus, for each group, an optimal mix of equipment and operating policies would have been obtained, and a direct comparison across groups could have been made. However, in running the model with this objective for the state-of-the-art systems group, it became obvious that the computational complexity of the problem would lead to prohibitive computer time expenses. With NASA/LeRC approval, a change in objective was agreed upon. Instead of simultaneously optimizing all systems within a group, a "one-at-a-time" optimization of the technologies was done for a selected set of technologies and regional combinations. This set is shown in Table IV-1. This allows a cost comparison of the best investment/operation combination across the technologies considered. Even with this revised objective, however, optimality was not reached for all the technologies considered. In particular, the AFB steam systems and the state-of-the-art steam systems were not run all the way to optimality because of computer expense limitations. In these cases, the solution and annual cost shown is the best solution found prior to termination. In these cases, the table also shows the estimated lower bound. The interpretation that should be made is that there may exist one or more additional solutions which have a lower cost than the best one found prior to termination. However, none of these additional solutions, if any exist, would have a lower annual cost

than that given by the lower bound. A more detailed explanation of the optimization methodology can be found in Appendix B.

This chapter contains a detailed description of the optimization results for each of the cases analyzed. The results are presented in the form of tables, with each table containing the following information:

- The definition of the case that was analyzed, including:
  - The industry under consideration.
  - The technology under consideration.
  - The region for which prices were assumed.
  - The buy-back rate that was assumed.
- The process steam and electric demands in each time period and the length of each time period.
- The equipment options available.
- The equipment actually selected.
- A summary of how the equipment was operated in each time period.
- The annual cost for the design chosen.

The tables provided in Section B of this chapter are organized as shown in Table VII-1. Entries in the table correspond to the page number in Section B.

Section C of this chapter contains energy flow diagrams for a selected number of the analyzed cases. Asterisks in Table VII-1 indicate these additional cases where greater detail about the quantities of fuel and electricity purchased and the quantities of steam and electricity generated, in each time period is provided.

Table VII-1

Orderir ; of Operating Summaries in Section VII-B.

(Entries in Table are page numbers in Section VII-b)

Industry	U.S./ Region	Buy-Back Rate (%)	Technology						
			No Cogen.	SOA Steam	AFB Steam	CCGT w/AFB	OCGT w/CDR	OCGT w/AFB	Combined Cycle
Newsprint	U.S.	60	7	8*	9*	10	11	12*	13*
	U.S.	100	7	14	15	—	—	—	—
	Wash.	60	16	17	18	19	20	21*	22
	Wash.	100	16	23	24	—	25	—	—
Writing Paper	U.S.	60	26	27	28	29*	—	30	31
	Wisc.	60	—	—	—	32*	—	30*	33
Chlorine	U.S.	60	34	35	36	37	—	38	39
	Texas	60	—	—	—	40*	—	38*	39
Petroleum Refining	U.S.	60	41	42	43	—	—	44	45
	Texas	60	—	—	—	47	—	44*	45

* These are cases for which detailed flow charts are displayed in Section C.

For various reasons the solutions obtained by the model in some cases were contrary to what might have been expected. We next examine some of these reasons.

In some cases, the number of devices picked by the model appears to be an inordinately large number. For example, in the Newsprint, U.S. average, no cogeneration 60% buy back rate case (VII-7), 19 50 psig package boilers were picked. The reason for this is that a size limitation of 20,700 lbs/hr. was placed on the package boilers that could be purchased. A similar phenomenon occurs in the Newsprint, U.S. average, advanced open cycle gas turbine-CIR 60% buy back case (VII-11), 16 package boilers and 9 1 MW open cycle gas turbine were picked. Again, there was a 1 MW size limitation on the package boilers. Different maximum sizes would probably have resulted in a smaller number of units being selected.

In some of the cases where the model solutions did not run to optimality (state-of-the-art and AFB steam turbines) steam was extracted at 150 psig when there was no demand for steam at 150 psig, in any of the time periods. Cases VII-9, VII-13, VII-14, and VII-28 are cases in which this happens. The reason for this is that had the solution process continued, the solution without extraction at 150 psig would have been found and recognized to be cheaper and retained instead of the solution with extraction at 150 psig. Thus, this quirk is a result of the solution process not having proceeded far enough.

A counter-intuitive result is obtained in the Newsprint, U.S. average, state-of-the-art turbines with a 100% buy back rate case (VII-14). Electricity is purchased at the peak demand rate of 77 MW in all three periods. However, all excess electricity purchased together with all its production is sold back to the grid. The reason for this is that by

purchasing as much electricity as it can to satisfy peak period demand, no standby capacity needs to be purchased in any of the three periods. Because of the 100% buy back rate, the excess in the two non-peak periods and the production can all be sold back to the grid. The solution chosen up to this point in the solution process purchases a standby capacity of 3.96 MW. This is only because the solution with 0 standby capacity purchase (which is cheaper) has not yet been evaluated by the solution process. Eventually, the latter solution would be picked over any solution that purchases standby electricity.

A fairly complicated case is now examined in detail. This is the Newsprint, national average, advanced open cycle gas turbine for combined cycle case with a 60% buy back rate (VII-13). 1 4.75 MW steam turbine and 3 10 MW open cycle gas turbines were purchased in addition to 14 package boilers. One of the gas turbines was used for reserve and no standby capacity was purchased. The amount of electricity purchased from the grid was 52.25 MW, 52.25 MW and 40.45 MW in each of the three periods respectively, resulting in an overall purchase of 75% of the electricity requirements. The steam turbine was run at full load in all three periods producing 4.75 MW of electricity while the gas turbines were run at 68%, 43% and 12.7% of capacity, respectively, in each of the 3 time periods. There was a sale of 0.55 MW of electricity in the peak period. No electricity was sold in either of the other two periods. Steam was extracted at 150 psig and throttled down to 50 psig contrary to engineering practice. As pointed out earlier, this is because the solution with no extraction at 150 psig has not yet been analyzed by the solution process.

B. Tables Giving Details About the Optimization Results

INDUSTRY: 2621 - NEWSPRINT

REGION: U.S. AVERAGE

CASE: NO COGENERATION; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

19 50 PSIG PACKAGE BOILERS OF SIZE 20.7×10^3 LB/HR AND FIRING NATURAL GAS

OPERATING SUMMARY:

BOUGHT ALL OF ITS ELECTRICITY FROM THE GRID.

SUPPLIED ALL STEAM AND HOT WATER REQUIREMENTS FROM THE PACKAGE BOILERS.

HOT WATER MADE AVAILABLE BY THROTTLING FROM 50 PSIG STEAM.

ONE OF THE PACKAGE BOILERS WAS USED AS BACKUP.

OUTPUT WAS 96% OF CAPACITY IN THE PEAK PERIOD.

OUTPUT WAS 88% OF CAPACITY IN THE SECOND PERIOD.

OUTPUT WAS 61% OF CAPACITY IN THE THIRD PERIOD.

ANNUALIZED COST:

M$ 37.84754

INDUSTRY: 26 - NEWSPRINT

REGION: U.S. AVERAGE

CASE: SOA STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL
CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD)
CONVENTIONAL STEAM TURBINES
PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

1 14.25 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F, EXHAUST AT 50 PSIG. NO EXTRACTION.
3 100,000 LB/HR HIGH PRESSURE BOILERS PRODUCING STEAM AT 850 PSIG/825°F, AND FIRING COAL.
4 50 PSIG PACKAGE BOILERS OF SIZE 20.7 x 10^3 LB/HR, AND FIRING NATURAL GAS.

OPERATING SUMMARY:

PURCHASED ABOUT 80% OF ITS ELECTRIC REQUIREMENTS.
PURCHASED STANDBY ELECTRICAL CAPACITY OF 14.25 MW.
NO ELECTRICITY SOLD.
OPERATED TURBINE AT 100% OF CAPACITY (14.25 MW) IN THE PEAK AND SECOND PERIODS, AND AT 78% OF CAPACITY (11.08 MW) IN THE THIRD PERIOD.
EXHAUST FROM THE TURBINE SATISFIED 68%, 81%, AND 100% OF THE DEMANDS FOR 50 PSIG STEAM AND HOT WATER IN THE PEAK, SECOND, AND THIRD PERIODS RESPECTIVELY.
DESUPERHEATING OF HIGH PRESSURE STEAM SATISFIED ABOUT 7% OF PROCESS DEMANDS IN BOTH THE PEAK AND SECOND PERIODS. NO DESUPERHEATING IN THIRD PERIOD. ALL HOT WATER REQUIREMENTS MET BY THROTTLING 50 PSIG STEAM.
ONE OF THE PACKAGE BOILERS USED AS BACKUP. REST GENERATED ABOUT 25% OF THE PROCESS REQUIREMENTS IN THE PEAK PERIOD, 12% IN THE SECOND PERIOD, AND WERE SHUT OFF IN THE THIRD PERIOD.

ANNUALIZED COST: M$ 29.67913

LOWER BOUND: M$ 23.4116

IN[illegible]STI[illegible] 26 N[illegible]PR[illegible]

REGION: U.S. AVERAGE

CASE: AFB STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
AFB BOILERS FIRING COAL.
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

1 19 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F, EXTRACTED STEAM AT 150 PSIG, EXHAUST STEAM AT 50 PSIG.
4 100,000 LB/HR AFB BOILERS.

OPERATING SUMMARY:

PURCHASED ABOUT 78% OF ITS ELECTRICITY FROM THE GRID.
PURCHASED 16.6 MW OF STANDBY CAPACITY.
OPERATED TURBINE AT 87% OF CAPACITY (16.6 MW) IN THE PEAK PERIOD.
OPERATED TURBINE AT 81% OF CAPACITY (15.4 MW) IN THE SECOND PERIOD.
OPERATED TURBINE AT 57% OF CAPACITY (10.8 MW) IN THE THIRD PERIOD.
SOLD NO ELECTRICITY.
EXTRACTED STEAM WAS 67.5 MBTU/HR IN THE PEAK PERIOD, 34.8 MBTU/HR IN THE SECOND PERIOD, AND ZERO IN THE THIRD PERIOD. EXTRACTED STEAM THROTTLED DOWN TO 50 PSIG. NO DIRECT DESUPERHEATING OF HIGH PRESSURE STEAM TO LOWER PRESSURES. THE REMAINING STEAM AND HOT WATER NEEDS OBTAINED FROM TURBINE EXHAUST.

ANNUALIZED COST:

M$ 27.9187

LOWER BOUND:

M$ 23.9232

INDUSTRY: 2621 - NEWSPRINT

REGION: U.S. AVERAGE

CASE: ADVANCED CLOSED CYCLE GAS TURBINE - AFB; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
ADVANCED CLOSED CYCLE GAS TURBINE - AFB EQUIPPED WITH HEAT RECOVERY BOILER.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

2 50 PSIG PACKAGE BOILERS OF SIZE 5,000 LB/HR AND FIRING NATURAL GAS.
4 10 MW COGENERATORS (CLOSED CYCLE GAS TURBINES - AFB).

OPERATING SUMMARY:

PURCHASED ONLY 48% OF ITS ELECTRIC REQUIREMENTS.
GENERATED ABOUT 52% OF ELECTRIC DEMAND IN EACH TIME PERIOD; 40 MW IN THE PEAK, 36.3 MW IN THE SECOND, AND 25.03 MW IN THE THIRD.
COGENERATORS PRODUCED STEAM AT 600 PSIG (SAT.), 450 PSIG, 150 PSIG, AND 50 PSIG. ALSO PRODUCED HOT WATER.
THE PACKAGE BOILERS WERE USED ONLY IN THE PEAK PERIOD -- TO PRODUCE .92 MBTU/HR OF 50 PSIG STEAM (LESS THAN ONE HALF OF 1% OF THE REQUIREMENT). THE COGENERATORS SUPPLIED PRACTICALLY ALL THE STEAM AND HOT WATER REQUIREMENTS.
STANDBY CAPACITY OF 10 MW WAS PURCHASED. ONE OF THE PACKAGE BOILERS USED AS BACKUP.
SOLD NO ELECTRICITY.

ANNUALIZED COST:

M$ 27.0456

INDUSTRY: 2621 - NEWSPRINT

REGION: U.S. AVERAGE

CASE: ADVANCED OPEN CYCLE GAS TURBINE - (CDR); 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.

ADVANCED OPEN CYCLE GAS TURBINE FIRING COAL DERIVED RESIDUAL, EQUIPPED WITH HEAT RECOVERY BOILER.

PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

16 50 PSIG PACKAGE BOILERS OF SIZE 20.7×10^3 LB/HR AND FIRING NATURAL GAS.

9 1 MW COGENERATORS (OPEN CYCLE GAS TURBINE - CDR)

OPERATING SUMMARY:

BOUGHT 98% OF ELECTRIC REQUIREMENTS. USED ONE OF THE COGENERATORS AS BACKUP SO DID NOT HAVE TO BUY STANDBY ELECTRICAL CAPACITY. THE REMAINING 8 WERE OPERATED AT 99% OF CAPACITY (7.9 MW) IN THE PEAK PERIOD, 9% OF CAPACITY IN THE SECOND PERIOD (.72 MW), AND 3% OF CAPACITY (.25 MW) IN THE THIRD PERIOD.

ONE OF THE PACKAGE BOILERS WAS USED AS BACKUP. THE REMAINING 15 WERE RUN AT 100% OF CAPACITY IN BOTH THE PEAK AND SECOND PERIODS, AND AT 70% OF CAPACITY IN THE THIRD PERIOD.

THE PACKAGE BOILERS SUPPLIED 86% OF THE STEAM AND HOT WATER REQUIREMENTS IN THE PEAK PERIOD, 95% IN THE SECOND PERIOD, AND 94% IN THE THIRD PERIOD. THE REST WERE SUPPLIED BY THE COGENERATORS.

ANNUALIZED COST:

M$ 37.8218

INDUSTRY: 2621 - Newsprint
REGION: National Average
CASE: Cogeneration with advanced open cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140^oF (MBtu/hr)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS: Package boilers firing natural gas, residual oil, and distillate oil
Advanced open cycle gas turbine firing coal in an AFB furnace, and equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 3 10MW Cogenerators (Advanced open cycle gas turbines - AFB)

OPERATING SUMMARY: Purchased about 77% of electricity requirements. Purchase of standby was only 5.18MW. Electricity generated in plant was 25.18MW, 21.2MW, and 9.26MW for the 1st, 2nd and 3rd periods respectively. These represent operating levels of 84%, 71% and 31%. In terms of percentage of requirements they were 33%, 30% and 19% for the 3 periods.
Precisely the right amount of 600psig saturated steam was produced at these operating levels to make it possible to satisfy the 50psig steam and hot water requirements by dethrottling.

ANNUALIZED COST: M$ 30.00 - (Optimal)

COMPONENTS OF COST: Cogenerators (Cap.+O&M) = M$ 7.354, Coal = M$ 8.50, Electricity purchase = M$ 14.0
Standby capacity = M$ .124

INDUSTRY: 2621 - Newsprint
REGION: National average
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (MBtu/hr)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle, firing coal derived residual oil, and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 14 gas firing 50psig package boilers of size 20,000 lb/hr
1 4.75MW steam turbine. Input steam at 850psig/825°F extracting at 150psig and condensing
3 10MW open cycle gas turbine (cogenerator)

OPERATING SUMMARY: Purchased 75% of electricity requirements. Purchased no standby capacity. Sold .55MW electricity in peak period. Had reserve capacity of 10MW.

Period 1: Cogenerators at 68% of capacity. Produced 20.55MW of elec, 108.6 MBtu/hr high pressure steam and 13.1 MBtu/hr of hot water. The steam turbine run at full capacity with 47.99 MBtu/hr of the high pressure steam, 32.53 MBtu/hr of which was extracted at 150psig. The remaining high pressure steam, the extracted steam, the condensed steam, and the output of package boilers went to satisfy the demands for 50psig steam and for hot water.

Period 2: Cogenerators at 43% of capacity produced 13MW elec, 81.2 MBtu/hr of HP steam and 8.3 MBtu/hr hot water. Steam turbines at full load. Input = 47.99 MBtu/hr, extraction at 32.53 MBtu/hr.

Period 3: Cogenerators at 12.7% of capacity produced 3.8MW elec, 47.99 MBtu/hr HP steam, and 2.4 MBtu/hr hot water. HP steam used to run steam turbine at full load.

ANNUALIZED COST: M$ 38.47 Lower bound = M$ 33.645

INDUSTRY: - NEWSPRINT

REGION: U.S. AVERAGE

CASE: SOA STEAM TURBINES; 100% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL, AND COAL (WITH FGD).
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

3 4.75 MW TURBINES. INPUT STEAM AT 850 PSIG/825°F, EXTRACTION AT 150 PSIG, EXHAUST AT 50 PSIG.
2 300,000 LB/HR HIGH PRESSURE BOILERS FIRING COAL AND PRODUCING STEAM AT 850 PSIG/825°F.

OPERATING SUMMARY:

PURCHASED ELECTRICITY AT THE PEAK RATE OF DEMAND (77 MW) IN ALL THREE PERIODS.
OPERATED TURBINES AT 67% OF CAPACITY (9.5 MW) IN THE PEAK PERIOD, EXTRACTING 0 MBTU/HR.
OPERATED TURBINES AT 91% OF CAPACITY (12.96 MW) IN THE SECOND PERIOD, EXTRACTING 95.5 MBTU/HR.
OPERATED TURBINES AT 69% OF CAPACITY (9.87 MW) IN THE THIRD PERIOD, EXTRACTING 10.1 MBTU/HR.
PURCHASED STANDBY CAPACITY OF 3.96 MW.
SOLD BACK ALL EXCESS ELECTRICITY PURCHASED TOGETHER WITH ALL OF ITS PRODUCTION.
DESUPERHEATED HIGH PRESSURE STEAM TO 50 PSIG STEAM AT 167.6 MBTU/HR IN THE PEAK PERIOD. EXTRACTED STEAM THROTTLED DOWN TO 50 PSIG. THE REST OF THE PROCESS REQUIREMENTS MET BY TURBINE EXHAUST.

ANNUALIZED COST:

M$ 31.5242

LOWER BOUND:

INDUSTRY: 2621 - NEWSPRINT

REGION: U.S. AVERAGE

CASE: AFB STEAM TURBINES; 100% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
AFB BOILERS FIRING COAL.
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

1 19 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F, EXTRACTION AT 150 PSIG, EXHAUST AT 50 PSIG.
5 100,000 LB/HR OF AFB BOILERS PRODUCING 850 PSIG/825°F STEAM.

OPERATING SUMMARY:

PURCHASED ELECTRICITY AT THE PEAK RATE OF DEMAND (77 MW) IN ALL THREE PERIODS.
OPERATED TURBINE AT 87% OF CAPACITY (16.6 MW) IN THE PEAK PERIOD.
OPERATED TURBINE AT 81% OF CAPACITY (15.4 MW) IN THE SECOND PERIOD.
OPERATED TURBINE AT 57% OF CAPACITY (10.8 MW) IN THE THIRD PERIOD.
SOLD BACK ALL EXCESS ELECTRICITY PURCHASED TOGETHER WITH ALL OF ITS PRODUCTION, THUS AVOIDING HAVING TO BUY STANDBY CAPACITY. BUT THEN HAD TO INSTALL A BACKUP H-P BOILER.
EXTRACTED STEAM WAS 76.5 MBTU/HR IN THE PEAK PERIOD, 34.8 MBTU/HR IN THE SECOND, AND ZERO IN THE THIRD PERIOD.
THE REST OF THE PROCESS REQUIREMENTS WERE SUPPLIED BY TURBINE EXHAUST.

ANNUALIZED COST:

M$ 27.8409

LOWER BOUND:

M$ 23.6524

INDUSTRY: 2621 - NEWSPRINT

REGION: STATE OF WASHINGTON

CASE: NO COGENERATION; 60 % BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

10 50 PSIG PACKAGE BOILERS OF SIZE 42.4 x 10^3 LB/HR AND FIRING RESIDUAL OIL

OPERATING SUMMARY:

BOUGHT ALL OF ITS ELECTRICITY FROM THE GRID.

ALL STEAM AND HOT WATER REQUIREMENTS SATISFIED BY THE PACKAGE BOILERS.

HOT WATER OBTAINED BY THROTTLING 50 PSIG STEAM. ONE OF THE BOILERS WAS USED AS BACKUP.

OUTPUT IN THE PEAK PERIOD WAS 94% OF CAPACITY.

OUTPUT IN THE SECOND PERIOD WAS 86% OF CAPACITY.

OUTPUT IN THE THIRD PERIOD WAS 60% OF CAPACITY.

ANNUALIZED COST:

IN[illegible]STR[illegible] 26[illegible] N[illegible]PR[illegible]

REGION: STATE OF WASHINGTON

CASE: SOA STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.

CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD).

CONVENTIONAL STEAM TURBINES

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

2 4.75 MW TURBINES. INPUT STEAM AT 850 PSIG/825°F, EXHAUST AT 50 PSIG. NO EXTRACTION.

2 300,000 LB/HR BOILERS FIRING COAL, AND PRODUCING HIGH PRESSURE STEAM AT 850 PSIG/825°F.

OPERATING SUMMARY:

BOUGHT 86% OF ITS ELECTRIC REQUIREMENTS.

OPERATED BOTH TURBINES AT 100% LOAD IN ALL THREE TIME PERIODS.

BOUGHT STANDBY CAPACITY OF 4.75 MW.

SOLD NO ELECTRICITY.

ABOUT 34% OF THE TOTAL 50 PSIG STEAM AND HOT WATER REQUIREMENTS WERE SATISFIED BY THROTTLING THE HIGH PRESSURE STEAM. THE REST WERE SATISFIED BY EXHAUST STEAM FROM THE TURBINE.

ANNUALIZED COST:

M$ 21.9589

LOWER BOUND:

INDUSTRY: 2(- NEWSPRINT

REGION: STATE OF WASHINGTON

CASE: AFB STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140^{o} F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.

AFB BOILERS FIRING COAL.

CONVENTIONAL STEAM TURBINES.

PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

1 4.75 MW TURBINE. INPUT STEAM AT 850 PSIG/825^{o}F, AND EXHAUST AT 50 PSIG. NO EXTRACTION.

4 100,000 LB/HR AFB BOILERS PRODUCING STEAM AT 850 PSIG/825^{o}F.

OPERATING SUMMARY:

PURCHASED 93% OF ITS ELECTRIC REQUIREMENTS FROM THE GRID.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 4.75 MW.

SOLD NO ELECTRICITY.

OPERATED TURBINES AT 100% LOAD IN ALL THE TIME PERIODS, WITH EXHAUST STEAM AT 130 MBTU/HR.

ABOUT 65% OF TOTAL REQUIREMENTS OF 50 PSIG STEAM AND WATER WAS SUPPLIED BY DESUPERHEATING DIRECTLY FROM THE HIGH PRESSURE STEAM. THE OTHER 35% WAS FROM THE TURBINE EXHAUST.

ANNUALIZED COST:

M$ 18.4852

LOWER BOUND:

M$ 13.9047

INDUSTRY: 2621 - NEWSPRINT

REGION: STATE OF WASHINGTON

CASE: ADVANCED CLOSED CYCLE GAS TURBINE - AFB; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
ADVANCED CLOSED CYCLE GAS TURBINE - AFB EQUIPPED WITH HEAT RECOVERY BOILER.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

2 50 PSIG PACKAGE BOILERS OF SIZE 5,000 LB/HR AND FIRING NATURAL GAS.
4 10 MW COGENERATORS (CLOSED CYCLE GAS TURBINE - AFB).

OPERATING SUMMARY:

PURCHASED ABOUT 49% OF ELECTRIC REQUIREMENTS FROM THE GRID.
PURCHASED STANDBY ELECTRICAL CAPACITY OF 36.3 MW.
SOLD 3.67 MW OF ELECTRICITY IN THE PEAK PERIOD.
ONE OF THE PACKAGE BOILERS WAS USED AS BACKUP. THE OTHER ONE WAS OPERATED ONLY IN THE PEAK PERIOD TO PRODUCE .9 MBTU/HR OF 50 PSIG STEAM.
THE COGENERATORS SUPPLIED THE REST OF THE STEAM AND HOT WATER REQUIREMENTS.
THE COGENERATORS WERE RUN AT: 100% OF CAPACITY (40 MW) IN THE PEAK PERIOD
91% OF CAPACITY (36.3 MW) IN THE SECOND PERIOD
63% OF CAPACITY (25.03 MW) IN THE THIRD PERIOD.

ANNUALIZED COST:

M$ 21.4301

INDUSTRY: 2621 - NEWSPRINT

REGION: STATE OF WASHINGTON

CASE: ADVANCED OPEN CYCLE GAS TURBINE - (CDR); 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.

ADVANCED OPEN CYCLE GAS TURBINE FIRING COAL DERIVED RESIDUAL, EQUIPPED WITH HEAT RECOVERY BOILER.

PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

10 50 PSIG PACKAGE BOILERS OF SIZE 42.4 x 10^3 LB/HR, AND FIRING RESIDUAL OIL.

OPERATING SUMMARY:

PURCHASED ALL OF ITS ELECTRIC REQUIREMENTS.

ONE OF THE PACKAGE BOILERS USED AS BACKUP.

THE REST WERE OPERATED AT: 94% OF CAPACITY IN THE PEAK PERIOD

86% OF CAPACITY IN THE SECOND PERIOD

60% OF CAPACITY IN THE THIRD PERIOD

TO SATISFY THE 50 PSIG STEAM AND HOT WATER DEMANDS.

ANNUALIZED COST:

M$ 27.4619 -- SAME SOLUTION AS NO COGENERATION.

INDUSTRY: 2621 - Newsprint
REGION: State of Washington
CASE: Advanced open cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (MBtu/hr)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS: Package boilers firing natural gas and distillate oil
Advanced open cycle gas turbine - AFP equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 3 10MW cogenerators (open cycle gas turbine - AFB)

OPERATING SUMMARY: Purchased about 71% of electricity from the grid. Purchased standby electrical capacity of 1.2MW
Peak period: Operated turbines at 84% of capacity to produce 25.2MW elec and 423.5 MBtu/hr of 600psig saturated steam. Sold 4MW of elec.
2nd period: Operated turbines at 71% of capacity to produce 21.2MW elec and 385 MBtu/hr of 600psig saturated steam.
3rd period: Operated turbines at 31% of capacity to produce 9.3MW elec and 269.5 MBtu/hr of 600psig saturated steam.
Produced steam dethrottled to satisfy 50psig steam and hot water demands.

ANNUALIZED COST: M$ 21.834 - (Optimal)

COMPONENTS OF COST: Cogenerators (cap.+O&M) = M$ 7.354, Coal = M$ 8.537, Electricity purchased = M$ 5.938, Electricity sold = M$ .022, Standby capacity = M$ .028

INDUSTRY: 2621 - Newsprint
REGION: Washington
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (MBtu/hr)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle, firing coal derived residual oil, and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 10 residual oil fired 50psig package boilers of size 42,000 lb/hr

OPERATING SUMMARY: Purchased all of its electricity. Same solution as base (no cogeneration) case. One package boiler used as back up, and the remaining 9 operated to meet thermal demands.

ANNUALIZED COST: M$ 27.4619 - (Optimal)

[illegible]

REGION: STATE OF WASHINGTON

CASE: SOA STEAM TURBINES; 100% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

<u>EQUIPMENT OPTIONS:</u>

PACKAGE BOILERS FIRING NATURAL OIL AND DISTILLATE OIL.

CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD).

CONVENTIONAL STEAM TURBINES.

PURCHASED ELECTRICITY.

<u>EQUIPMENT SELECTED:</u>

4 100,000 LB/HR HIGH PRESSURE BOILERS FIRING COAL AND PRODUCING 600 PSIG/750°F STEAM.

2 50 PSIG PACKAGE BOILERS OF SIZE 10.35×10^3 LB/HR FIRING NATURAL GAS.

<u>OPERATING SUMMARY:</u>

BOUGHT ELECTRICITY AT THE PEAK RATE OF DEMAND IN ALL THREE PERIODS.

SOLD BACK EXCESS PURCHASED ELECTRICITY.

DID NOT PURCHASE STANDBY ELECTRICAL CAPACITY.

USED ONE PACKAGE BOILER AS BACKUP. THE OTHER PRODUCED ONLY IN THE PEAK PERIOD - 9.92 MBTU/HR.

THE HIGH PRESSURE BOILERS MET THE REMAINING PROCESS STEAM AND HOT WATER DEMANDS. ONE HIGH PRESSURE BOILER USED AS BACKUP.

<u>ANNUALIZED COST:</u>

M$ 20.1037

<u>LOWER BOUND:</u>

M$ 13.9062

INDUSTRY: 26: NEWSPRINT

REGION: STATE OF WASHINGTON

CASE: AFB STEAM TURBINES; 100% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS :FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
AFB BOILERS FIRING COAL.
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

1 4.75 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F, EXHAUST AT 50 PSIG. NO EXTRACTION.
4 100,000 LB/HR AFB BOILERS PRODUCING STEAM AT 850 PSIG/825°F.

OPERATING SUMMARY:

PURCHASED ELECTRICITY AT THE PEAK RATE OF DEMAND (77 MW) IN ALL THREE TIME PERIODS.
OPERATED TURBINE AT 25% OF CAPACITY (1.19 MW) IN THE PEAK PERIOD.
OPERATED TURBINE AT 100% OF CAPACITY (4.75 MW) IN THE SECOND PERIOD.
OPERATED TURBINE AT 100% OF CAPACITY (4.75 MW) IN THE THIRD PERIOD.
SOLD BACK ALL EXCESS ELECTRICITY PURCHASED TOGETHER WITH ALL OF ITS PRODUCTION, THUS HAVING TO BUY STANDBY CAPACITY OF ONLY .7 MW.
DESUPERHEATING TO 50 PSIG STEAM WAS 380.6 MBTU/HR, 255 MBTU/HR, AND 139.5 MBTU/HR IN THE RESPECTIVE TIME PERIODS. REST OF PROCESS DEMANDS SATISFIED BY TURBINE EXHAUST.

ANNUALIZED COST:

M$ 18.3974

LOWER BOUND:

M$ 13.9062

IN STI N PR

REGION: STATE OF WASHINGTON

CASE: ADVANCED OPEN CYCLE GAS TURBINE - (CDR); 100% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140^{o} F (MBTU/HR)
PERIOD 1	657.00	1320	77	260.70	162.80
PERIOD 2	6876.60	1200	70	237.00	148.00
PERIOD 3	1226.40	840	49	165.90	103.60

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.

ADVANCED OPEN CYCLE GAS TURBINE - CDR

PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

10 50 PSIG PACKAGE BOILERS OF SIZE 42.4 x 10^3 LB/HR AND FIRING RESIDUAL OIL.

OPERATING SUMMARY:

PURCHASED ELECTRICITY AT PEAK DEMAND RATE OF (77 MW) AND SOLD BACK EXCESS.

PRODUCED NO ELECTRICITY.

ONE PACKAGE BOILER USED AS BACKUP. THE REST OPERATED AT:

94% OF CAPACITY IN THE PEAK PERIOD

86% OF CAPACITY IN THE SECOND PERIOD

60% OF CAPACITY IN THE THIRD PERIOD

TO SATISFY THE PROCESS DEMANDS.

ANNUALIZED COST:

M$ 27.4617

EXCEPT FOR ELECTRICAL PURCHASE AND SALE RATE, SAME SOLUTION AS NO COGENERATION OR THE 60% BUY BACK RATE.

INDUSTRY: 2621 - WRITING PAPER, BLEACHED KRAFT

REGION: U.S. AVERAGE

CASE: NO COGENERATION; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140^{o} F (MBTU/HR)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

18 50 PSIG PACKAGE BOILERS OF SIZE 20.7×10^3 LB/HR, AND FIRING NATURAL GAS

6 150 PSIG PACKAGE BOILERS OF SIZE 50×10^3 LB/HR, AND FIRING NATURAL GAS

OPERATING SUMMARY:

ALL ELECTRIC REQUIREMENTS BOUGHT FROM GRID.

ALL OF THE HOT WATER REQUIREMENTS WERE SUPPLIED BY THROTTLING 150 PSIG STEAM IN THE PEAK PERIOD AND AGAIN IN THE THIRD PERIOD.

IN THE SECOND PERIOD THE 50 PSIG STEAM SUPPLIED THE HOT WATER REQUIREMENTS WHILE THE 150 PSIG STEAM SUPPLIED 54% OF THE 50 PSIG STEAM REQUIREMENTS. ONE 50 PSIG BOILER AND ONE 150 PSIG BOILER WERE USED AS BACKUPS.

OVERALL OUTPUT WAS 95% OF CAPACITY IN THE PEAK PERIOD.

OVERALL OUTPUT WAS 87% OF CAPACITY IN THE SECOND PERIOD.

OVERALL OUTPUT WAS 76% OF CAPACITY IN THE THIRD PERIOD.

ANNUALIZED COST:

M$ 42.20956

INDUSTRY: 2621 - WRITING PAPER, BLEACHED KRAFT

REGION: U.S. AVERAGE

CASE: SOA STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD).
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

1 28.5 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F, NO EXTRACTION, EXHAUST AT 50 PSIG.
2 300,000 LB/HR HIGH PRESSURE BOILERS PRODUCING STEAM AT 850 PSIG/825°F, AND FIRING COAL.
2 50 PSIG PACKAGE BOILERS OF SIZE 20.7 x 10^6 LB/HR AND FIRING NATURAL GAS.

OPERATING SUMMARY:

PURCHASED ABOUT 33% OF REQUIRED ELECTRICITY.
PURCHASED STANDBY ELECTRICAL CAPACITY OF 28.5 MW.
SOLD NO ELECTRICITY.
OPERATED TURBINE AT: 100% OF CAPACITY (28.5 MW) IN THE PEAK PERIOD
94% OF CAPACITY (26.9 MW) IN THE SECOND PERIOD
82% OF CAPACITY (23.5 MW) IN THE THIRD PERIOD.
ONE PACKAGE BOILER WAS USED AS BACKUP. THE OTHER WAS OPERATED ONLY IN THE PEAK PERIOD TO GENERATE 21.6 MBTU/HR OF 50 PSIG STEAM. ABOUT 6 MBTU/HR OF THE HIGH PRESSURE STEAM WAS DESUPERHEATED TO 50 PSIG STEAM IN THE PEAK PERIOD. THESE REMAINING PROCESS DEMANDS WERE SATISFIED BY EXHAUST STEAM FROM THE TURBINE.

ANNUALIZED COST:

M$ 25.8355

LOWER BOUND:

M$ 17.6719

INDUSTRY: 2621 - WRITING PAPER, BLEACHED KRAFT

REGION: U.S. AVERAGE

CASE: AFB STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL.
AFB BOILERS.
CONVENTIONAL STEAM TURBINES.
PURCHASED ELECTRICITY.

EQUIPMENT SELECTED:

2 19 MW STEAM TURBINES. INPUT STEAM AT 850 PSIG/825°F, EXTRACTION AT 150 PSIG AND EXHAUST AT 50 PSIG.
6 100,000 LB/HR AFB BOILERS PRODUCING STEAM AT 850 PSIG/825°F AND FIRING COAL.

OPERATING SUMMARY:

PURCHASED ONLY 33% OF ELECTRICITY REQUIREMENTS FROM THE GRID.
PURCHASED STANDBY ELECTRICAL CAPACITY OF 19.192 MW.
SOLD NO ELECTRICITY.
OPERATED TURBINES AT: 77% OF CAPACITY (29.2 MW) IN THE PEAK PERIOD
71% OF CAPACITY (26.8 MW) IN THE SECOND PERIOD
62% OF CAPACITY (23.4 MW) IN THE THIRD PERIOD.
EXTRACTED 150 PSIG STEAM AT 23 MBTU/HR IN THE PEAK PERIOD. NO EXTRACTION IN THE OTHER PERIODS. REMAINING STEAM AND HOT WATER DEMANDS SATISFIED BY EXHAUST STEAM FROM THE TURBINE.

ANNUALIZED COST:

M$ 23.8978

LOWER BOUND:

M[illegible]3.9[illegible]

INDUSTRY: 2621 - WRITING PAPER, BLEACHED KRAFT

REGION: U.S. AVERAGE

CASE: ADVANCED CLOSED CYCLE GAS TURBINE - AFB; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	HOT WATER @ 140° F (MBTU/HR)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL
ADVANCED CLOSED CYCLE GAS TURBINE - AFB, EQUIPPED WITH HEAT RECOVERY BOILER
PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

2 30 MW COGENERATORS (CLOSED CYCLE GAS TURBINE - AFB).
5 50 PSIG PACKAGE BOILERS OF SIZE 20.7 X 10^3 LB/HR AND FIRING NATURAL GAS.

OPERATING SUMMARY:

PURCHASED NO ELECTRICITY FROM THE GRID.
PURCHASED STANDBY ELECTRICAL CAPACITY OF 14 MW.
OPERATED COGENERATORS AT:
100% OF CAPACITY (60 MW) IN THE PEAK PERIOD, SOLD 16 MW.
100% OF CAPACITY (60 MW) IN THE SECOND PERIOD, SOLD 20 MW.
90% OF CAPACITY (53.9 MW) IN THE THIRD PERIOD, SOLD 18.7 MW.
ONE PACKAGE BOILER USED AS BACKUP. THE REMAINING 4 GENERATED 77 MBTU/HR AND 15 MBTU/HR OF 50 PSIG STEAM IN THE PEAK AND SECOND PERIODS RESPECTIVELY. WERE NOT OPERATED IN THE THIRD PERIOD.
THE COGENERATORS SUPPLIED REST OF STEAM AND HOT WATER REQUIREMENTS. SURPLUS 50 PSIG STEAM OF 20.5 MBTU/HR, 82.5 MBTU/HR AND 97.6 MBTU/HR NOT EFFICIENT TO SUBSTITUTE ONE OF THE PACKAGE BOILERS WITH A SMALLER SIZE (E.G., 5,000 LB/HR) BECAUSE OF BACKUP REQUIREMENT AND FUEL INPUT EFFICIENCY CONSIDERATIONS.

ANNUALIZED COST:

M$ 23.1682

INDUSTRY: 2621 - Writing paper, bleached kraft
REGION: National average; Wisconsin
CASE: Advanced open cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (MBtu/hr)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Advanced open cycle gas turbine firing coal in an AFB furnace and equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 2 gas firing 50psig package boilers of size 50,000 lb/hr - National average
4 gas firing 50psig package boilers of size 20,000 lb/hr - Wisconsin (run not given option of bigger sizes of package boilers)
4 10MW cogenerators (open cycle gas turbine - AFB).

OPERATING SUMMARY: Although different size package boilers were selected, same operation in both runs. Purchased only 4% of electrical requirements. Purchased standby electrical capacity of 10MW. Peak period operation of cogenerators was at 100%, produced 40MW elec. and 626.92 MBtu/hr of 600 psig steam. Second period operation of cogenerators was at 98%, produced 39.3MW elec and 620.00 MBtu/hr of 600psig steam. Third period operation was at 79%, produced 31.6MW elec and 545.6 MBtu/hr of 600psig steam. All 600psig steam dethrottled to 50psig steam and hotwater. In each case (National average or Wisconsin) one package boiler was used as back up. The rest operated only in the peak period to produce 55.1 MBtu/hr of 50psig steam.

ANNUALIZED COST:

	National Average		Wisconsin	
Cogenerators (cap.+O&M)	9.806		9.806	
Package boilers (cap.+O&M)	0.102		0.126	
Coal	15.855		15.276	
Gas	0.392		0.478	
Electricity purchase	0.528		0.584	
Standby capacity	0.240		0.240	
M$	26.923	Optimal	26.510	Optimal

INDUSTRY: 2621 - Writing paper, bleached kraft
REGION: National average
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (Mbtu/hr)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle, firing coal derived residual oil and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 29 gas fired 50psig package boilers of size 20,000 lb/hr

OPERATING SUMMARY: Purchased all of its electricity. Solution qualitatively same as base case. The only difference is that in the run for the base case, the solution was forced to include 6 150psig package boilers because the upper limit on 50psig package boilers available (17 plus 1 extra for back up) was hit. In this run the upper limits on all equipment were increased. The new solution thus avoids the extra cost for back up associated with installing the 150psig package boilers, and also operates selected equipment more intensively. One of the boilers used for back up. The remaining 28 operated at 99.8%, 90.7%, and 79.8% of capacity in the 1st, 2nd, and 3rd periods respectively.

ANNUALIZED COST: M$ 41.55; Lower bound = M$ 38.85; [Original base case = M$ 42.21 (Optimal)]

COMPONENTS: Package boilers (cap.+O&M) = .91279 Gas = 28.87222 Electricity = 11.76643

INDUSTRY: 2621 - Writing paper, bleached kraft
REGION: Wisconsin
CASE: Advanced closed cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140^{o}F (MBtu/hr)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Advanced closed cycle gas turbine - AFB equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 5 gas fired 50psig package boilers of size 20,000 lb/hr
2 30MW cogenerators (closed cycle gas turbine - AFB)

OPERATING SUMMARY: Purchased no electricity. Generated more than plant requirements in each time period. Purchased standby electrical capacity of 14.0MW. Operated cogenerators at 100% of capacity in the first 2 periods, and at 90% in period 3.

ELECTRICITY: Produced 60MW in peak period, sold 16MW
Produced 60MW in 2nd period, sold 20MW
Produced 53.93 in 3rd period, sold 18.73MW

STEAM FROM COGENERATORS:	600psig	450psig	150psig	50psig	Hot Water @ 140^{o}F	
Peak period	299.32	53.33	28.06	40.34	183.84	MBtu/hr
2nd period	299.32	53.33	28.06	40.34	183.84	MBtu/hr
3rd period	269.97	48.10	25.31	36.35	165.87	MBtu/hr

STEAM FROM PACKAGE BOILERS: 77.12 MBtu/hr in the peak period and 15.11 MBtu/hr in the 2nd. No steam production in 3rd period. One package boiler used only as backup.

ANNUALIZED COST: M$ 22.764 - (Optimal)

COMPONENTS OF COST: Cogenerators (cap.+O&M) = M$ 9.40, Package boilers (cap+O&M) = M$ .157, Coal = M$ 15.11, Gas = M$ 1.30, Standby capacity = M$ .336, Revenue from electricity sales = M$ 3.54

INDUSTRY: 2621 - Writing paper, bleached kraft
REGION: Wisconsin
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	HOT WATER @ 140°F (MBtu/hr)
PERIOD 1	1314	1320	44.0	418.0	264.0
PERIOD 2	6351	1200	40.0	380.0	240.0
PERIOD 3	1095	1056	35.2	334.4	211.2

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle firing coal derived residual, and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 21 gas fired 50psig package boilers of size 20,000 lb/hr
4 10MW combined cycle gas turbines (cogenerators)

OPERATING SUMMARY: Operated cogenerators at full load in all three periods (40MW), had to buy electricity (4MW) only in peak period. Sold 4.8MW in the third period. Purchased electrical standby capacity of 10MW. One package boiler used as back up. The rest produced 465.6, 403.6, 329.2 MBtu/hr in the first, second and third periods respectively. In each period the cogenerators produced 180.6 MBtu/hr of 1450psig steam, 10.3 MBtu/hr of 850psig steam, and 25.5 MBtu/hr of hot water. These, together with the surplus 50psig output made up for the hot water demand.

ANNUALIZED COST: M$ 47.31 Lower bound = M$ 46.84

COMPONENTS: Package boilers (cap.+O&M) = .66099 Cogenerators (cap.+O&M) = 2.77335
Coal = 20.04376 Natural gas = 23.35137 Standby capacity = .24000
Elec purchased = .34917 Elec sold = .11040

INDUSTRY: 2812 - CHLORINE

REGION: U.S. AVERAGE

CASE: NO COGENERATION; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	150 PSIG STEAM (MBTU/HR)	50 PSIG STEAM (MBTU/HR)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL, AND DISTILLATE OIL

PURCHASE ELECTRICITY

EQUIPMENT SELECTED:

4 50 PSIG PACKAGE BOILERS OF SIZE 20.7 x 10^3 LB/HR AND FIRING NATURAL GAS

4 150 PSIG PACKAGE BOILERS OF SIZE 50 x 10^3 LB/HR AND FIRING NATURAL GAS

OPERATING SUMMARY:

ALL ELECTRIC REQUIREMENTS BOUGHT FROM THE GRID.

HARDLY ANY THROTTLING TO THE 50 PSIG STEAM.

ONE OF THE 50 PSIG BOILERS AND ONE OF THE 150 PSIG BOILERS WERE USED AS BACKUPS.

REST GENERATED JUST ENOUGH TO MEET DEMANDS.

OUTPUT IN THE PEAK PERIOD WAS 83% OF CAPACITY.

OUTPUT IN THE SECOND PERIOD WAS 76% OF CAPACITY.

OUTPUT IN THE THIRD PERIOD WAS 68% OF CAPACITY.

ANNUALIZED COST:

M$ 35.1933

INDUSTRY: 2[illegible] - CHLORINE

REGION: U.S. AVERAGE

CASE: SOA STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	150 PSIG STEAM (MBTU/HR)	50 PSIG STEAM (MBTU/HR)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD)

CONVENTIONAL STEAM TURBINES

PURCHASE ELECTRICITY

EQUIPMENT SELECTED:

1 19 MW TURBINE. INPUT STEAM AT 850/825°F, EXTRACTION AT 150 PSIG, AND CONDENSING

3 100,000 LB/HR HIGH PRESSURE BOILERS FIRING COAL AND PRODUCING STEAM AT 850 PSIG/825°F

OPERATING SUMMARY:

PURCHASED 88% OF ELECTRIC REQUIREMENTS.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 11.25 MW.

OPERATED THE TURBINE AT ABOUT 60% OF CAPACITY (11.25 MW) IN THE PEAK PERIOD.

OPERATED THE TURBINE AT ABOUT 55% OF CAPACITY (10.57 MW) IN THE SECOND PERIOD.

OPERATED THE TURBINE AT ABOUT 51% OF CAPACITY (9.78 MW) IN THE THIRD PERIOD.

ALL STEAM REQUIREMENTS SATISFIED BY EXTRACTION; NO DIRECT DESUPERHEATING OF HIGH PRESSURE STEAM. PART OF THE 150 PSIG EXTRACTED STEAM THROTTLED TO SATISFY THE 50 PSIG STEAM DEMAND.

ANNUALIZED COST:

M$ 32.9706

LOWER BOUND:

M$ 27.4830

INDUSTRY: 2[illegible] - CHLORINE

REGION: U.S. AVERAGE

CASE: AFB STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	150 PSIG STEAM (MBTU/HR)	50 PSIG STEAM (MBTU/HR)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

AFB BOILERS

CONVENTIONAL STEAM TURBINES

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

1 4.75 MW TURBINE. INPUT STEAM AT 850 PSIG/825°F. EXTRACTION AT 150 PSIG AND CONDENSING.

2 100,000 LB/HR AFB BOILERS PRODUCING STEAM AT 850 PSIG/825°F.

3 50 PSIG PACKAGE BOILERS OF SIZE 20.7 x 10^3 LB/HR FIRING GAS.

OPERATING SUMMARY:

PURCHASED 95% OF ELECTRIC REQUIREMENTS.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 4.75 MW.

OPERATED TURBINES AT 100% OF CAPACITY IN ALL THREE PERIODS PRODUCING 32.5 MBTU/HR OF EXTRACTED 150 PSIG STEAM IN ALL PERIODS.

THE PACKAGE BOILERS PRODUCED 41.3 MBTU/HR, 22 MBTU/HR, AND 2.8 MBTU/HR OF 50 PSIG STEAM IN THE FIRST (PEAK), SECOND AND THIRD PERIODS RESPECTIVELY.

THE REMAINING 150 PSIG STEAM AND 50 PSIG STEAM DEMANDS IN EACH PERIOD WERE SATISFIED BY DESUPERHEATING HIGH PRESSURE STEAM.

ANNUALIZED COST: M$ [illegible].2780

LOWER BOUND: M$27.[illegible]7

INDUSTRY: 28[illegible] CHLORINE

REGION: U.S. AVERAGE

CASE: ADVANCED CLOSED CYCLE GAS TURBINE - AFB; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION (TONS/DAY)	ELECTRICITY (MW)	150 PSIG STEAM (MBTU/HR)	50 PSIG STEAM (MBTU/HR)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

ADVANCED CLOSED CYCLE GAS TURBINE - AFB, EQUIPPED WITH HEAT RECOVERY BOILER

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

2 50 PSIG STEAM PACKAGE BOILERS OF SIZE 5,000 LB/HR AND FIRING NATURAL GAS

1 30 MW COGENERATOR (CLOSED CYCLE GAS TURBINE - AFB)

OPERATING SUMMARY:

PURCHASED ABOUT 70% ITS ELECTRIC REQUIREMENTS FROM THE GRID.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 30 MW.

PEAK PERIOD: OPERATED COGENERATOR AT 100% OF CAPACITY (30MW) TO PRODUCE 30% OF ELECTRICITY DEMAND

SECOND PERIOD: OPERATED COGENERATOR AT 91% OF CAPACITY (27.3MW) TO PRODUCE 30% OF ELECTRICITY DEMAND

THIRD PERIOD: OPERATED COGENERATOR AT 82% OF CAPACITY (24.5MW) TO PRODUCE 30% OF ELECTRICITY DEMAND

ONE OF THE PACKAGE BOILERS WAS USED AS BACKUP, THE OTHER ONE PRODUCED ONLY IN THE PEAK PERIOD (1 MBTU/HR OF 50 PSIG STEAM).

PRACTICALLY ALL THE STEAM REQUIREMENTS WERE SATISFIED BY THE COGENERATOR.

ANNUALIZED COST:

M$ 30.47722

INDUSTRY: 2812 - Chlorine
REGION: National average; Texas
CASE: Advanced open cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	150psig STEAM (MBtu/hr)	50psig STEAM (MBtu/hr)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS: Package boilers firing natural gas and distillate oil
Advanced open cycle gas turbine firing coal in an AFB furnace and equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 4 gas firing 50psig package boilers of size 20,000 lb/hr
1 10MW cogenerator (open cycle gas turbine - AFB)

OPERATING SUMMARY: Same equipment selection and operation in both Texas and National average runs. Purchased about 88.5% of electricity requirements from the grid. Purchased standby capacity of 10MW. Operated turbine at 100% of capacity for all time periods producing 10MW of electricity and 156.73 MBtu/hr of 600psig steam. The 600psig steam was dethrottled to satisfy all the 150psig steam demands and some of the 50psig steam demands. The package boilers made up for remaining 50psig demands. One of the package boilers was only used as back up.

ANNUALIZED COST:

	National Average	Texas
Electricity	22.854	26.229
Coal	4.605	4.476
Gas	1.388	1.166
Standby Capacity	.240	.240
Package boilers (cap.+O&M)	.126	.126
Cogenerator (cap.+O&M)	2.455	2.455
M$	31.670 Optimal	34.69 Optimal

INDUSTRY: 2812 - Chlorine
REGION: National average; Texas
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	150psig STEAM (MBtu/hr)	50psig STEAM (MBtu/hr)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle, firing coal derived
Residual oil and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 4 gas fired 50psig package boilers of size 20,000 lb/hr
4 gas fired 150psig package boilers of size 50,000 lb/hr

OPERATING SUMMARY: Purchased all of its electricity. In both Texas and National average runs, same equipment selection as the base case run. No cogeneration.

ANNUALIZED COST: (Optimal)
National average = M$ 35.19 {Boilers = .353 Gas = 9.075 Electricity = 25.77}
Texas = M$ 37.57 {Boilers = .353 Gas = 7.627 Electricity = 29.59}

INDUSTRY: 2812 - Chlorine
REGION: Texas
CASE: Advanced closed cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (tons/day)	ELECTRICITY (MW)	150psig STEAM (MBtu/hr)	50psig STEAM (MBtu/hr)
PERIOD 1	876	660	99	137.5	74.03
PERIOD 2	4380	600	90	125.0	67.30
PERIOD 3	3504	540	81	112.5	60.57

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Advanced closed cycle gas turbine - AFB equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 2 gas fired, 50psig package boilers of size 5,000 lb/hr
1 30MW cogenerator (closed cycle gas turbine - AFB)

OPERATING SUMMARY: Purchased about 66% of electrical requirements from the grid.
Purchased standby electrical capacity of 30MW.
Operated turbine at full capacity in all time periods, producing 30MW elec, 149.66 MBtu/hr 600psig saturated steam, 26.67 MBtu/hr 450psig saturated steam, 14 MBtu/hr 150psig steam, 20MBtu/hr 50psig steam and 91.92 MBtu/hr of hot water. All the 600 and 450psig steam dethrottled to 150 and 50psig steam. Some of the hot water used as feedwater.
One package boiler operated in the peak period to produce 1 MBtu/hr of 50psig steam. This made up for the shortfall in the output of the cogenerator. The other package boiler used as back up.

ANNUALIZED COST: M$ 32.731 - (Optimal)

COMPONENTS OF COST: Turbine (cap.+O&M) = M$ 4.7, Pack boiler (cap.+O&M) = M$ .037, Coal = M$ 7.763, Gas = M$ .004, Electricity purchased = M$ 19.508, Standby = M$ .72

INDUSTRY: 2911 - PETROLEUM REFINING

REGION: U.S. AVERAGE

CASE: NO COGENERATION; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION 10^3 BARRELS/DAY	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	150 PSIG STEAM (MBTU/HR)	450 PSIG STEAM (MBTU/HR)
PERIOD 1	836.28	262.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

CONVENTIONAL HIGH PRESSURE BOILERS FIRING GAS, RESIDUAL OIL AND COAL (WITH FGD)

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

6 CONVENTIONAL COAL FIRED BOILERS PRODUCING HIGH PRESSURE STEAM AT 850 PSIG/825°F

SIZE = 300 x 10^3 LB/HR

OPERATING SUMMARY:

BOUGHT ALL OF ELECTRICITY FROM THE GRID.

DESUPERHEATED THE PRODUCED STEAM TO MEET THE DEMANDS FOR THE LOWER PRESSURE STEAM.

ONE BOILER WAS USED AS BACKUP.

ANNUALIZED COST:

M$ 66.6217

INDUSTRY: 2911 - TROLEUM REFINING

REGION: U.S. AVERAGE

CASE: SOA STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION 10^3 BARRELS/DAY	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	150 PSIG STEAM (MBTU/HR)	450 PSIG STEA (MBTU/HR)
PERIOD 1	836.28	262.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

CONVENTIONAL HIGH PRESSURE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND COAL (WITH FGD)

CONVENTIONAL STEAM TURBINES

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

5 4.75 MW STEAM TURBINES. INPUT STEAM AT 850 PSIG/825°F EXTRACTION AT 150 PSIG, AND EXHAUST AT 50 PSIG.

6 300,000 LB/HR HIGH PRESSURE BOILERS PRODUCING STEAM AT 850 PSIG/825°F, AND FIRING COAL

OPERATING SUMMARY:

PURCHASED 47% OF ELECTRIC REQUIREMENTS FROM THE GRID.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 16.6 MW.

OPERATED TURBINES AT: 93% OF CAPACITY (22 MW) IN THE PEAK PERIOD
89% OF CAPACITY (21.2 MW) IN THE SECOND PERIOD
78% OF CAPACITY (18.5 MW) IN THE THIRD PERIOD
63% OF CAPACITY (15 MW) IN THE FOURTH PERIOD.

EXTRACTED STEAM WAS SLIGHTLY MORE THAN THE 150 PSIG STEAM REQUIREMENTS IN THE FIRST 2 PERIODS, AND EXACTLY EQUAL IN THE LAST 2 PERIODS. THE 450 PSIG STEAM REQUIREMENTS WERE MET BY DESUPERHEATING HIGH PRESSURE STEAM. EXHAUST STEAM MORE THAN MET THE NEEDS FOR 50 PSIG STEAM.

ANNUALIZED COST:

M$ 65.7002

LOWER BOUND:

[illegible]

INDUSTRY: 2911 - PETROLEUM REFINING

REGION: U.S. AVERAGE

CASE: AFB STEAM TURBINES; 60% BUY BACK RATE

DEMANDS	HOURS	PRODUCTION 10^3 BARRELS/DAY	ELECTRICITY (MW)	50 PSIG STEAM (MBTU/HR)	150 PSIG STEAM (MBTU/HR)	450 PSIG STEAM (MBTU/HR)
PERIOD 1	836.28	262.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS:

PACKAGE BOILERS FIRING NATURAL GAS, RESIDUAL OIL AND DISTILLATE OIL

AFB BOILERS

CONVENTIONAL STEAM TURBINES

PURCHASED ELECTRICITY

EQUIPMENT SELECTED:

3 4.75 MW STEAM TURBINES. INPUT STEAM AT 850 PSIG/825°F. EXTRACTION AT 150 PSIG STEAM, EXHAUST AT 50 PSIG.

4 600,000 LB/HR AFB BOILERS PRODUCING 850 PSIG/825°F STEAM.

OPERATING SUMMARY:

PURCHASED 64% OF ELECTRIC REQUIREMENTS.

PURCHASED STANDBY ELECTRICAL CAPACITY OF 4.3 MW

OPERATED TURBINES AT 97% (13.78 MW) OF CPAPCITY IN ALL TIME PERIODS, EXTRACTING 118.4 MBTU/HR OF 150 PSIG STEAM AND EXHAUSTING 495 MBTU/HR OF 50 PSIG STEAM.

THE 450 PSIG REQUIREMENTS WERE SATISFIED BY DESUPERHEATING HIGH PRESSURE STEAM.

ONE OF THE BOILERS USED AS BACKUP.

ANNUALIZED COST:

M$ 59.2624

LOWER BOUND:

M$ 49.8696

INDUSTRY: 2911 - Petroleum Refining
REGION: National average, Texas
CASE: Advanced open cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (10^3bbl/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	150psig STEAM (MBtu/hr)	450psig STEAM (MBtu/hr)
PERIOD 1	836.28	252.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Advanced open cycle gas turbine firing coal in an AFB furnace, and equipped with heat recovery boiler
Conventional high pressure boilers firing coal
Purchased electricity

EQUIPMENT SELECTED: 7 gas fired 50psig package boilers of size 20,000 lb/hr
4 30MW cogenerators (open cycle gas turbine - AFB)

OPERATING SUMMARY: No purchase of electricity or standby capacity. Sold electricity in each of the four periods. Peak period operation of cogenerators at 100%, produced 120MW elec and 1880.76 MBtu/hr 600psig steam, sold 78MW elec. Second period operation of cogenerators at 100%, produced 120MW elec and 1880.76 MBtu/hr 600psig steam, sold 80MW elec. Third period operation of cogenerators at 79%, produced 94.73MW elec and 1636.25 MBtu/hr 600psig steam, sold 60.73MW elec. Fourth period operation of cogenerators at 54%, produced 64.89MW elec and 1347.5 MBtu/hr 600psig steam, sold 36.89MW elec. All the 600psig steam dethrottled to 50, 150, and 150psig steams. One package boiler used as back up, the rest produced 140.50 MBtu/hr in the peak period and 44.24 MBtu/hr in the second period. Were shut down in last two periods.

ANNUALIZED COST:

	National Average	Texas
Cogenerators (cap.+O&M)	25.32	25.32
Package boilers (cap.+O&M)	0.22	0.22
Coal	46.00	44.71
Gas	1.90	1.59
Electricity Sales	-13.13	-15.00
M$	60.11 Optimal	56.64 Optimal

INDUSTRY: 2911 - Petroleum Refining
REGION: National Average; Texas
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (10^3bbl/day)	ELECTRICITY (MW)	50psig STEAM	150psig STEAM (MBtu/hr)	450psig STEAM (MBtu/hr)
PERIOD 1	836.28	262.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil, and residual oil
Conventional high pressure steam turbines
Advanced open cycle gas turbines for combined cycle firing coal derived residual, and equipped with heat recovery boilers
Purchased electricity

EQUIPMENT SELECTED: 15 gas firing 50psig package boilers of size 20,000 lb/hr
3 gas firing 150psig package boilers of size 50,000 lb/hr
33 10MW combined cycle gas turbines (cogenerators)

OPERATING SUMMARY: Same equipment selection and operation in both the national average run and the Texas run. Difference in objective function reflects differences in prices. Purchased no electricity or standby capacity. Sold electricity in each of 4 periods.

OPERATION OF COGENERATORS:

	Electricity Produced (MW)	Electricity Sold (MW)	450psig Steam (MBtu/hr)	150psig Steam (MBtu/hr)	Hot Water (MBtu/hr)	% Capacity
Period 1	326.64	284.64	1474.80	84.27	208.40	99
Period 2	310.29	270.29	1400.95	80.05	197.96	94
Period 3	263.74	229.74	1190.80	68.05	168.27	80
Period 4	217.20	189.20	980.66	56.04	138.57	66

The cogenerators were operated primarily to satisfy the demand for the 450psig steam, for which they were the only source. Some hot water used as feed water, the rest useless. The 150psig package boilers were the only source for the 150psig steam. Except for the peak period when about 10 MBtu/hr were supplied by dethrottling, the 50psig package boilers met all the demands for that steam type. One of the 150psig package boilers was used as back up. The same applies to the 50psig package boilers.

(CONTINUED)

INDUSTRY: 2911 - Petroleum Refining
REGION: National average; Texas
CASE: Advanced open cycle gas turbine for combined cycle; 60% buy back rate

CONTINUED

COST:

M$	National Average	Texas
Package boilers (cap.+O&M)	.6426	.6426
Cogenerators (cap.+O&M)	22.8802	22.8802
Coal	144.6347	144.6321
Natural gas	20.0576	16.8576
Electric Sales (at 60% rate)	-46.3117	-52.9345
Total (at 60% rate)	141.9034(Opt.)	132.078(Opt.)
Total (at 100% rate)	111.0289	96.7883

INDUSTRY: 2911 - Petroleum Refining
REGION: Texas
CASE: Closed cycle gas turbine - AFB; 60% buy back rate

DEMANDS	HOURS	PRODUCTION (10^3bbl/day)	ELECTRICITY (MW)	50psig STEAM (MBtu/hr)	150psig STEAM (MBtu/hr)	450psig STEAM (MBtu/hr)
PERIOD 1	836.28	262.5	42	351.225	114.975	1555.050
PERIOD 2	5414.89	250.0	40	334.500	109.500	1481.000
PERIOD 3	2090.69	212.5	34	284.325	93.075	1258.850
PERIOD 4	418.14	175.0	28	234.150	76.650	1036.700

EQUIPMENT OPTIONS: Package boilers firing natural gas, distillate oil and residual oil
Conventional high pressure boilers firing coal
Advanced closed cycle gas turbine - AFB, equipped with heat recovery boiler
Purchased electricity

EQUIPMENT SELECTED: 4 gas fired 50psig package boilers of size 20,000 lb/hr
5 coal fired 850psig boilers of size 100,000 lb/hr
2 100MW advanced closed cycle gas turbines (cogenerators) - AFB

OPERATING SUMMARY: No purchase of electricity or of standby capacity

OPERATION OF COGENERATORS:

	Elec. Produced	Elec. Sold	600psig Sat. Steam	450psig Steam	150psig Steam	50psig Steam	Hot Water	% Capacity
Period 1	200	158.0	997.53	177.78	93.54	132.46	612.80	100
Period 2	200	160.0	997.53	177.78	93.54	132.46	612.80	100
Period 3	200	166.0	997.53	177.78	93.54	132.46	612.80	100
Period 4	191.8	163.8	957.89	170.72	89.82	129.08	588.52	95.9

(The electricity figures are in MW and those for the thermal outputs in MBtu/hr) One high pressure boiler and one package boiler are used as back ups. The package boilers were operated only in the peak period. They produced 54.32 MBtu/hr of 50psig steam. The rest of the thermal demands were made up by the high pressure boilers. Only the cogenerators were operated in the in the fourth period.

ANNUALIZED COST: M$ 58.64 Lower bound = M$ 56.55

C. Flow Diagrams for a Selected Number of Cases

1. Overview

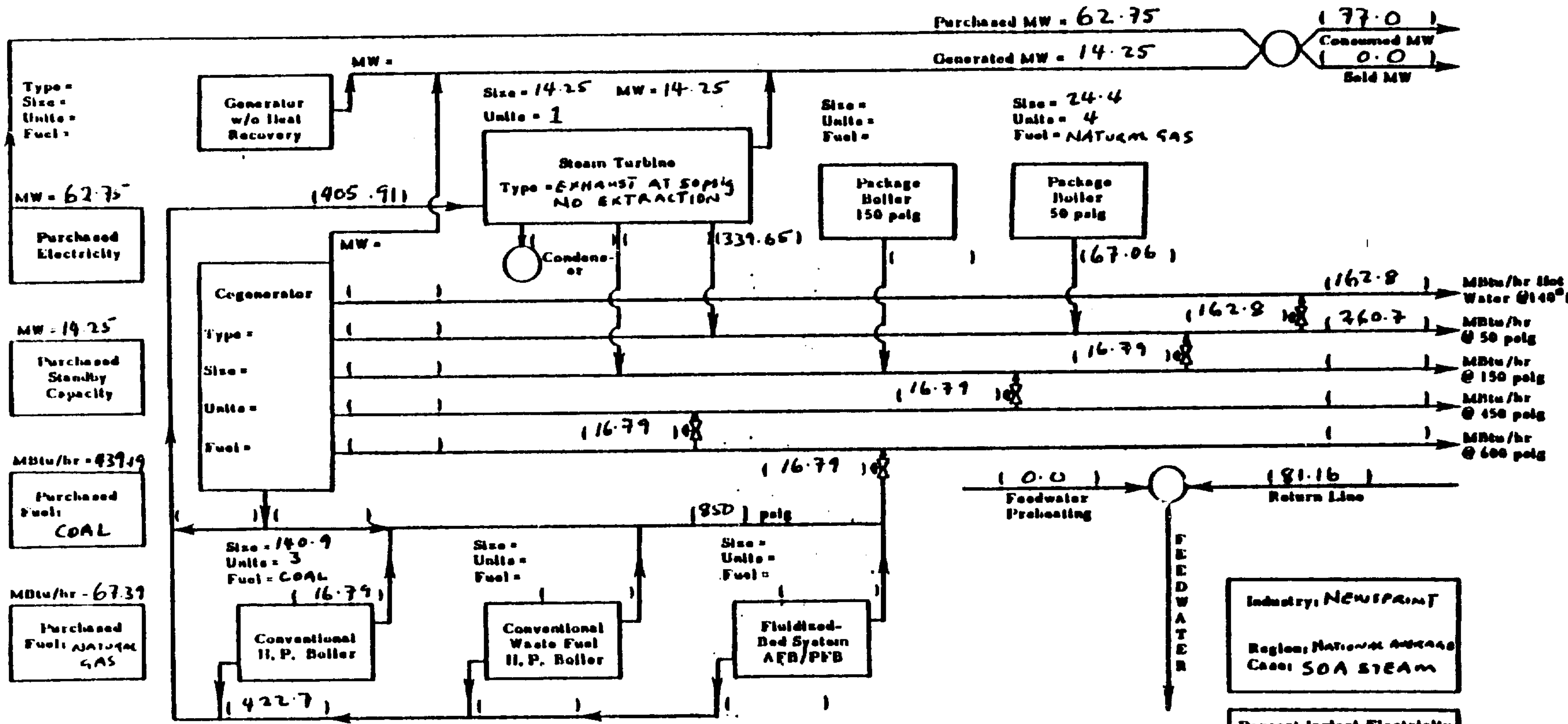
In this section, detailed energy flow charts for some selected cases are presented. The specific cases and their order of appearance by page number are given in Table VII-2.

The layout of the flow chart was designed to be general enough to accomodate all the various cases and options that were run. Any specific case, therefore, may not need all the boxes for description. For example, in the Newsprint, National average, state-of-the-art turbine, 60% buy back rate case (VII-51), Cogeneration, Package boiler 150 psig, Conventional waste fuel H.P. boiler and Generator w/o heat recovery boxes are not used because they don't apply. Also, there is no demand for 150 psig, 450 psig or 600 psig steam in Time Period (TP) 1. (This can be seen in the lower left hand corner box. There is one such chart for each of the three time periods.) Thus, the steam lines corresponding to these non-existant demands are not applicable here. In the furthest left hand column, the purchased electricity, standby capacity and fuels are reported while in the furthest right hand column, the case, percent implant electricity generated in that period, the annual plant cost and the computer cost for this run are reported. Various fuel and electricity prices are also reported in the middle of the chart.

Table VII-2

Ordering of Operating Summaries in Section VII-C
(Entries in Table are page numbers in Section VII-C)

Industry	U.S./ Region	Buy-Back Rate (%)	Technology						
			No Cogen.	SOA Steam	AFB Steam	CCGT w/AFB	OCGT w/CDR	OCGT w/AFB	Combined Cycle
Newsprint	U.S.	60	—	51	54	—	—	57	60
	U.S.	100	—	—	—	—	—	—	—
	Wash.	60	—	—	—	—	—	63	—
Writing Paper	U.S.	60	—	—	—	66	—	—	—
	Wisc.	60	—	—	—	69	—	72	—
Chlorine	Texas	60	—	—	—	75	—	78	—
Petroleum Refining	Texas	60	—	—	—	—	—	81	—



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D	1	77	162.8	260.7					657
E									
M									
A									
N									
D									
S									
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

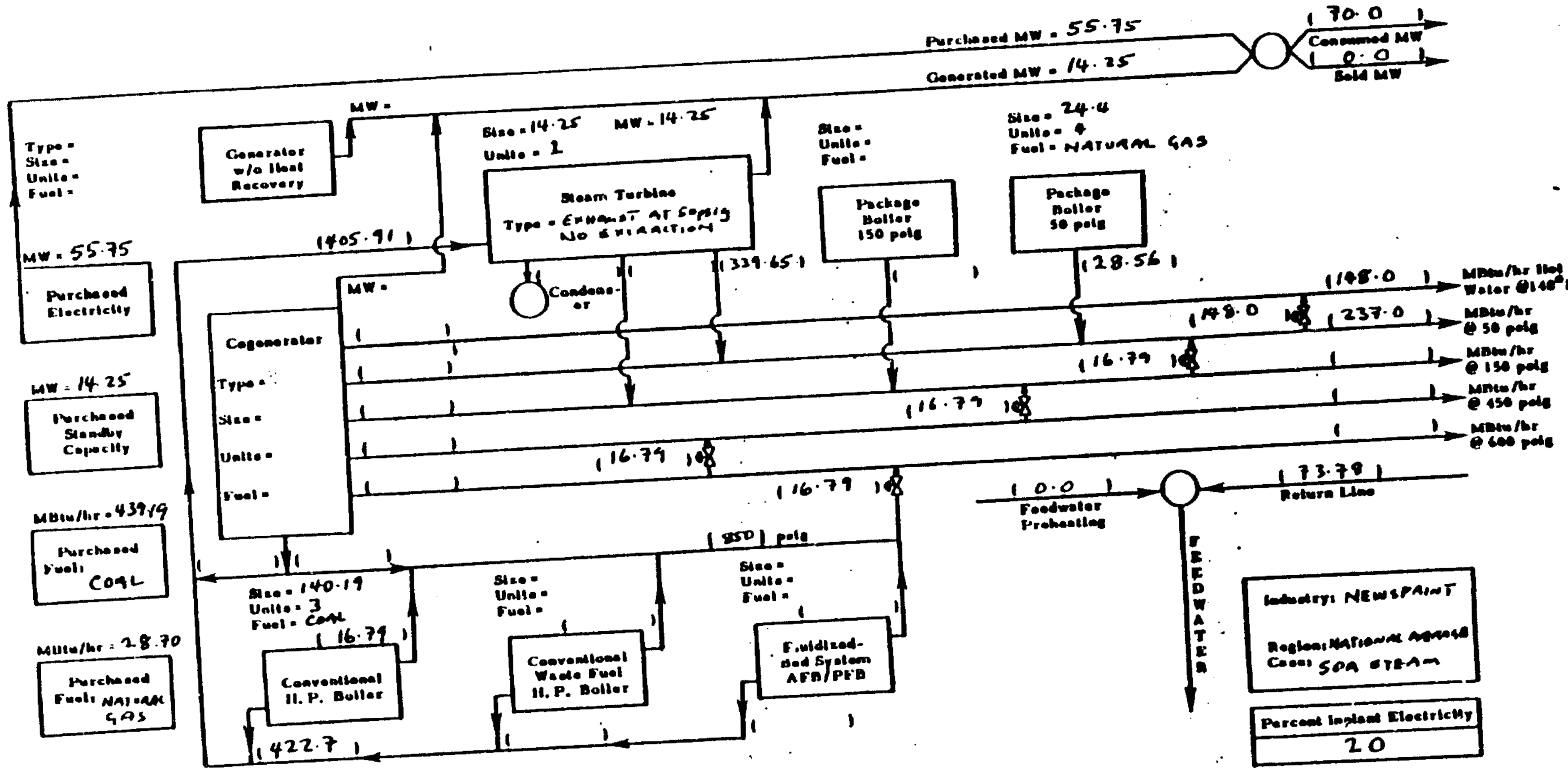
CCEQC	= 0.13	
PCOAL	= 2.12	\$/MBtu
PRESIDUAL	= 5.38	\$/MBtu
PDISTILLATE	= 6.84	\$/MBtu
PGAS	= 5.28	\$/MBtu
PELECD	= 2.43	\$/kW/mo
PELECE	= 0.03	\$/kWh
PSTDBY	= 2.10	\$/kW/mo
PSELL	= 0.02	\$/kWh

Percent Inplant Electricity
19.51

Annual Plant Cost M\$
29.68

Run Cost \$
109.51

MBtu = million Btu
M\$ = million dollars



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	
	2	70	148.0	237.0					6876.6

CCEQC = 0.13
PCOAL = 2.12 $/MBtu
PRESIDUAL = 5.38 $/MBtu
PDISTILLATE = 6.04 $/MBtu
PGAS = 6.28 $/MBtu
PELECD = 2.93 $/kW/mo
PELECE = 0.03 $/kWh
PSTDBY = 2.00 $/kW/mo
PSELL = 0.02 $/kWh

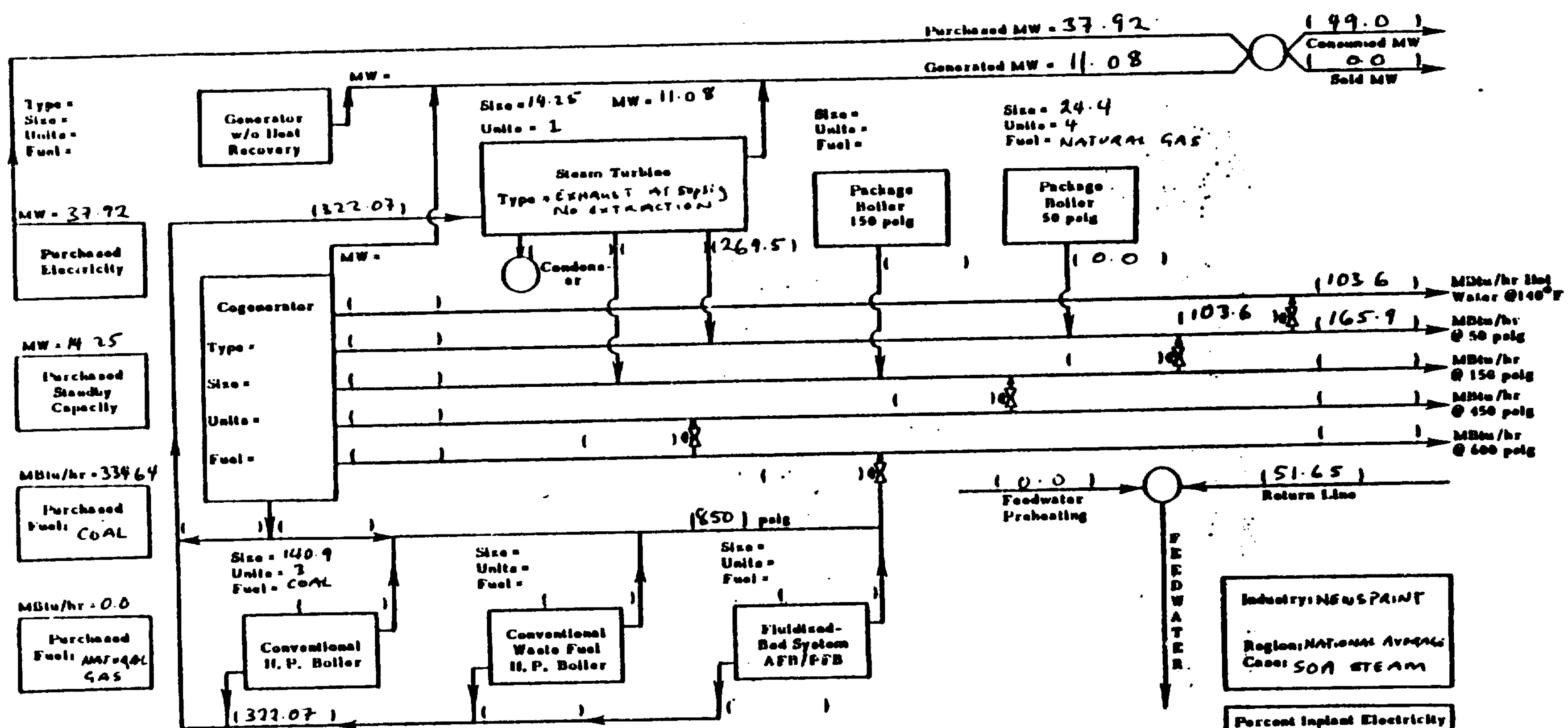
Industry: NEWSPRINT
Region: NATIONAL AVERAGE
Case: 50A STEAM

Percent Inplant Electricity
20

Annual Plant Cost M$
29.68

Run Cost $
109.51

MBtu = million Btu
M$ = million dollars



	TF	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D E M A N D S									
	3	49	103.6	165.9					2264
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= 0.13	
PCOAL	= 2.12	\$/MBtu
PRESIDUAL	= 5.38	\$/MBtu
PDISTILLATE	= 6.94	\$/MBtu
PGAS	= 5.28	\$/MBtu
PELECD	= 2.43	\$/kW/mo
PELECE	= 0.03	\$/kWh
PSTDBY	= 2.00	\$/kW/mo
PSELL	= 0.02	\$/kWh

Industry: NEWSPRINT

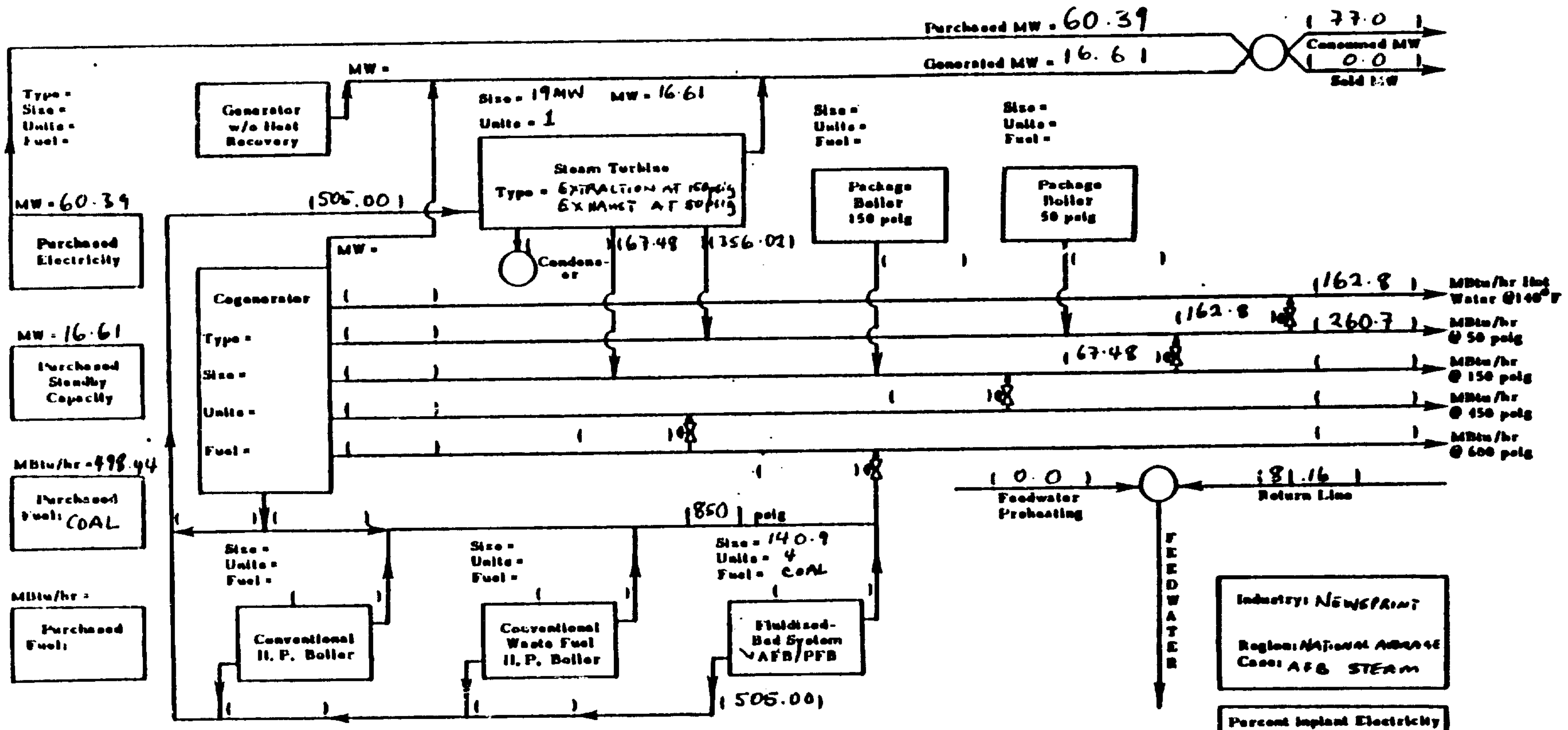
Region: NATIONAL AVERAGE
Case: SOA STEAM

Percent Inplant Electricity
23

Annual Plant Cost M\$
29.68

Run Cost \$
109.51

MBtu = million Btu
M\$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D	1	77	162.8	260.7					657
E									
M									
A									
N									
D									
S									
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC = 0.13
PCOAL = 2.12 $/MBtu
PRESIDUAL = 5.38 $/MBtu
PDISTILLATE = 6.89 $/MBtu
PGAS = 5.18 $/MBtu
PELECD = 2.93 $/kW/mo
PELECE = 0.03 $/kWh
PSTDBY = 2.00 $/kW/mo
PSELL = 0.02 $/kWh

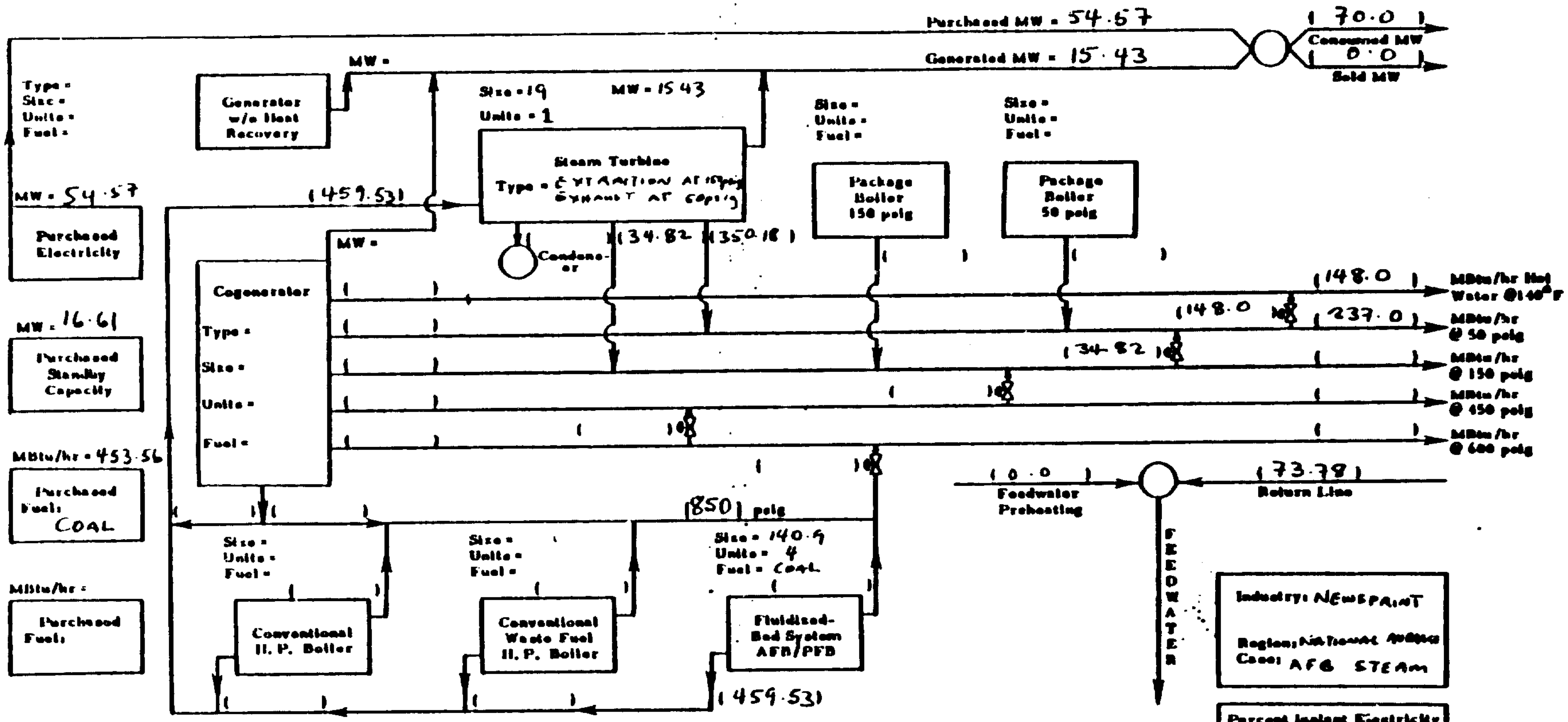
Industry: NEWSPRINT
Region: NATIONAL AVERAGE
Case: AFB STEAM

Percent Inplant Electricity
21.6

Annual Plant Cost M$
27.92

Run Cost $
61.89

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	2	70	146.0	237.0					6876.6
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

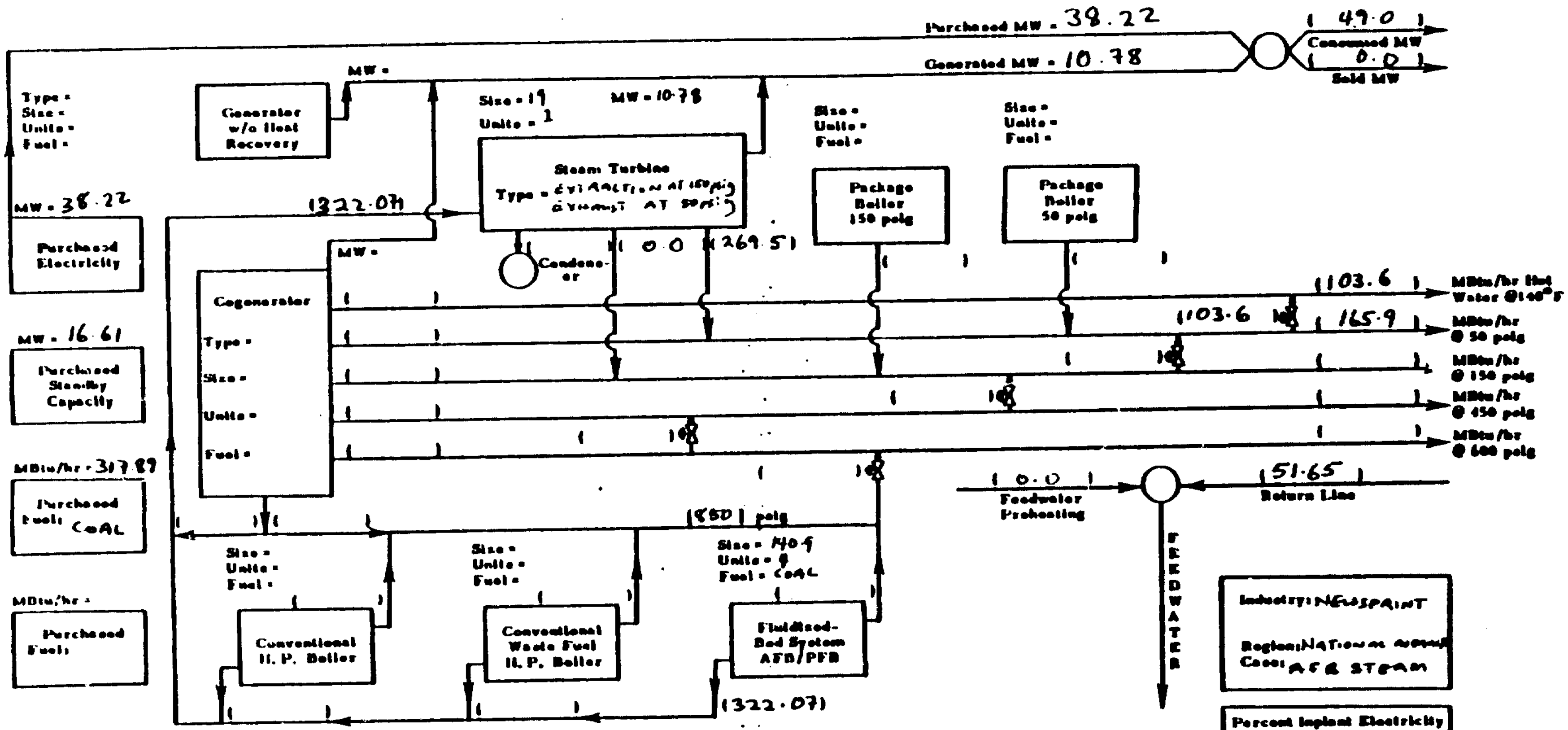
CCEQC	= 0.13	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.38	$/MBtu
PDISTILLATE	= 6.84	$/MBtu
PGAS	= 5.25	$/MBtu
PELECD	= 2.43	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh

Percent Inplant Electricity
22

Annual Plant Cost M$
27.92

Run Cost $
61.89

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	3	49	103.6	165.9					1226.4
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	=0.13	
PCOAL	=2.12	$/MBtu
PRESIDUAL	=5.38	$/MBtu
PDISTILLATE	=6.94	$/MBtu
PGAS	=5.28	$/MBtu
PELECD	=2.93	$/kW/mo
PELECE	=0.03	$/kWh
PSTDBY	=2.00	$/kW/mo
PSELL	=0.02	$/kWh

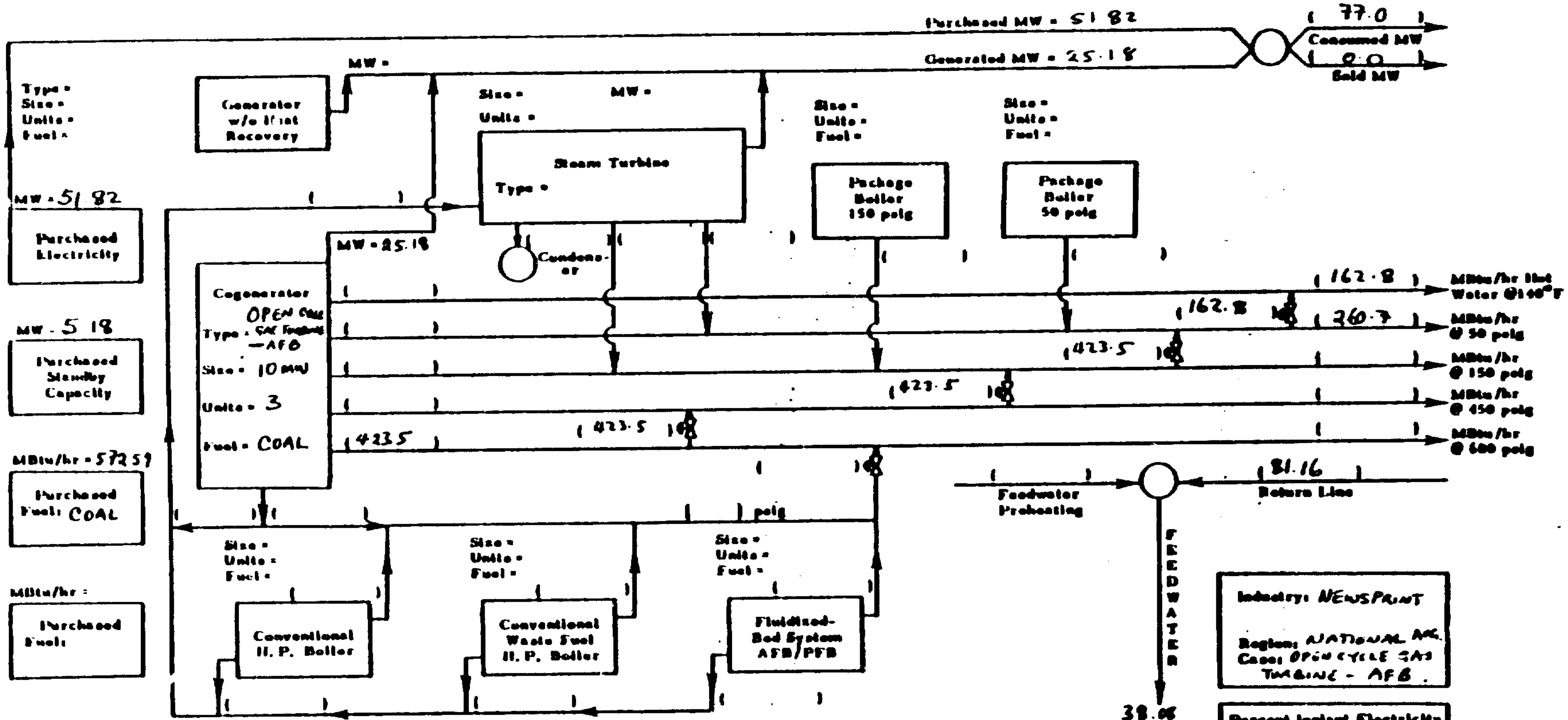
Industry: NEWSPRINT
Region: NATIONAL AVERAGE
Case: AFB STEAM

Percent Inplant Electricity
22

Annual Plant Cost M$
27.92

Run Cost $
61.89

MBtu = million Btu
M$ = million dollars



Industry: NEWSPRINT

Region: NATIONAL AVG.
Case: OPEN CYCLE GAS TURBINE - AFB.

Percent Inplant Electricity
33

Annual Plant Cost M$
30.0

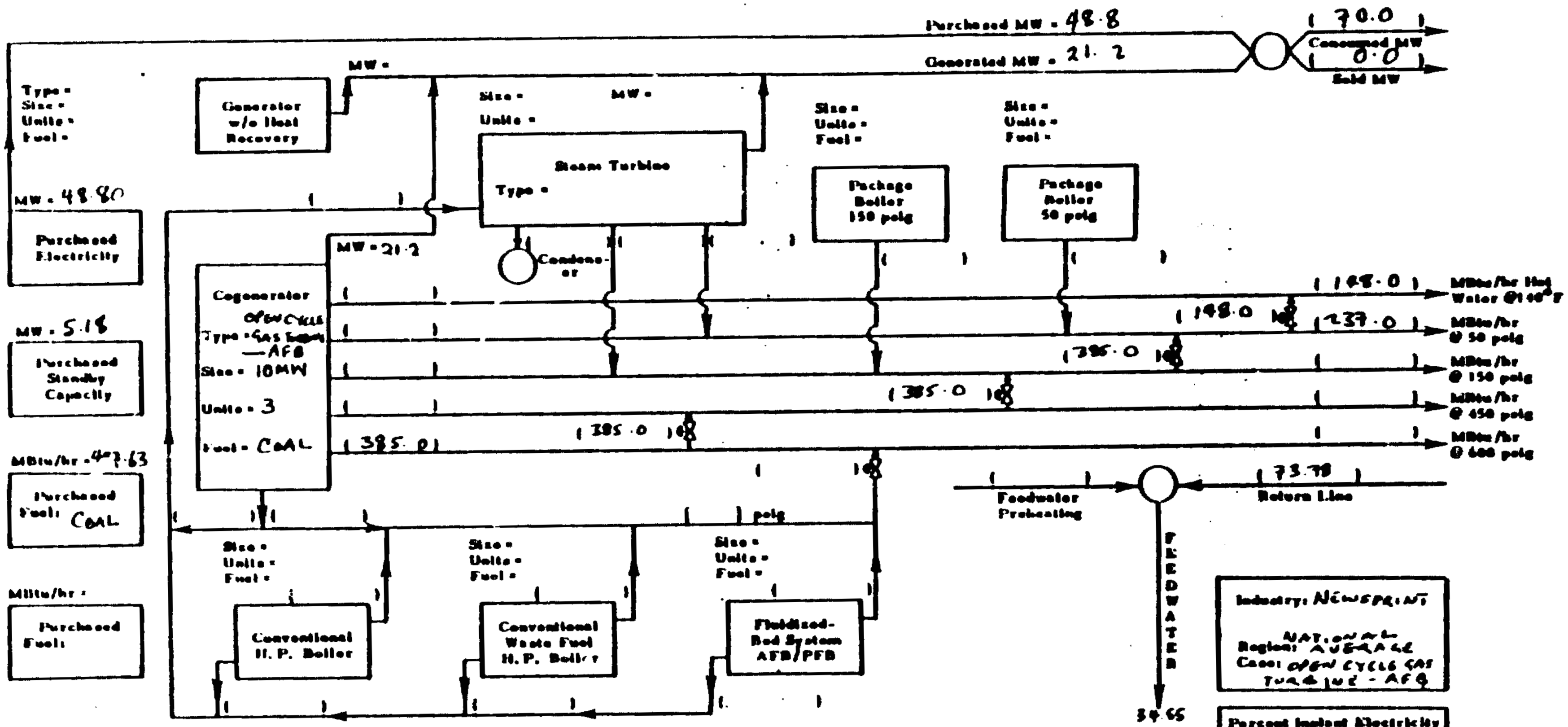
Run Cost $
44

MBtu = million Btu
M$ = million dollars

DEMANDS

TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
1	77	162.8	260.7					657.0
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.38	$/MBtu
PDISTILLATE	= 6.84	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.43	$/kW/mo
ELECE	= .029	$/kWh
PSTDBY	= 2.0	$/kW/mo
PSELL	= .02	$/kWh



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D E M A N D S									
	2	70.0	148.0	237.0					6876.6
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

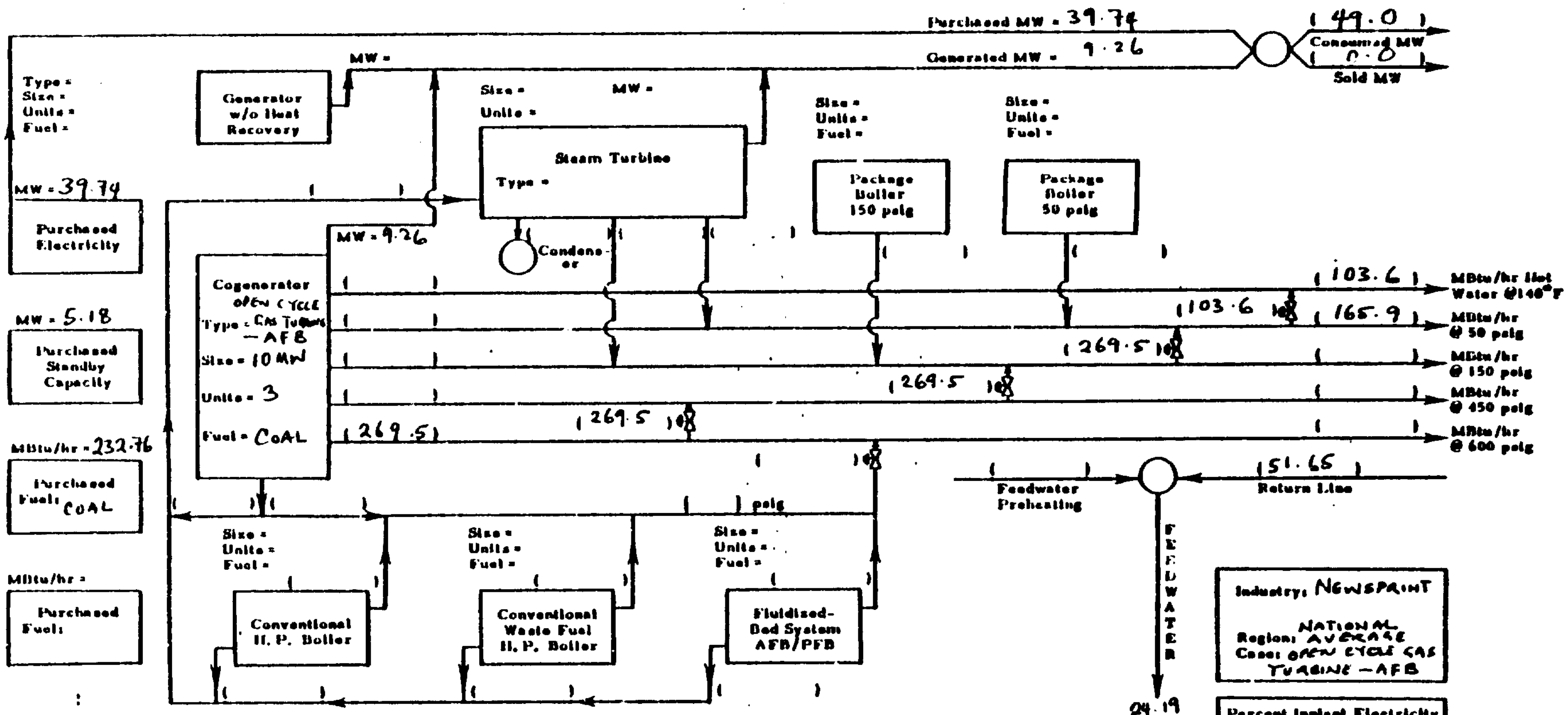
CCEQC	= .1066	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.36	$/MBtu
PDISTILLATE	= 6.84	$/MBtu
PGAS	= 5.18	$/MBtu
PELECD	= 2.93	$/kW/mo
PELECE	= .029	$/kWh
PSTDBY	= 1.00	$/kW/mo
PSELL	= .02	$/kWh

Percent Inplant Electricity
30.0

Annual Plant Cost M$
30.0

Run Cost $
44

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	3	49	103.6	165.9					1226.4
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

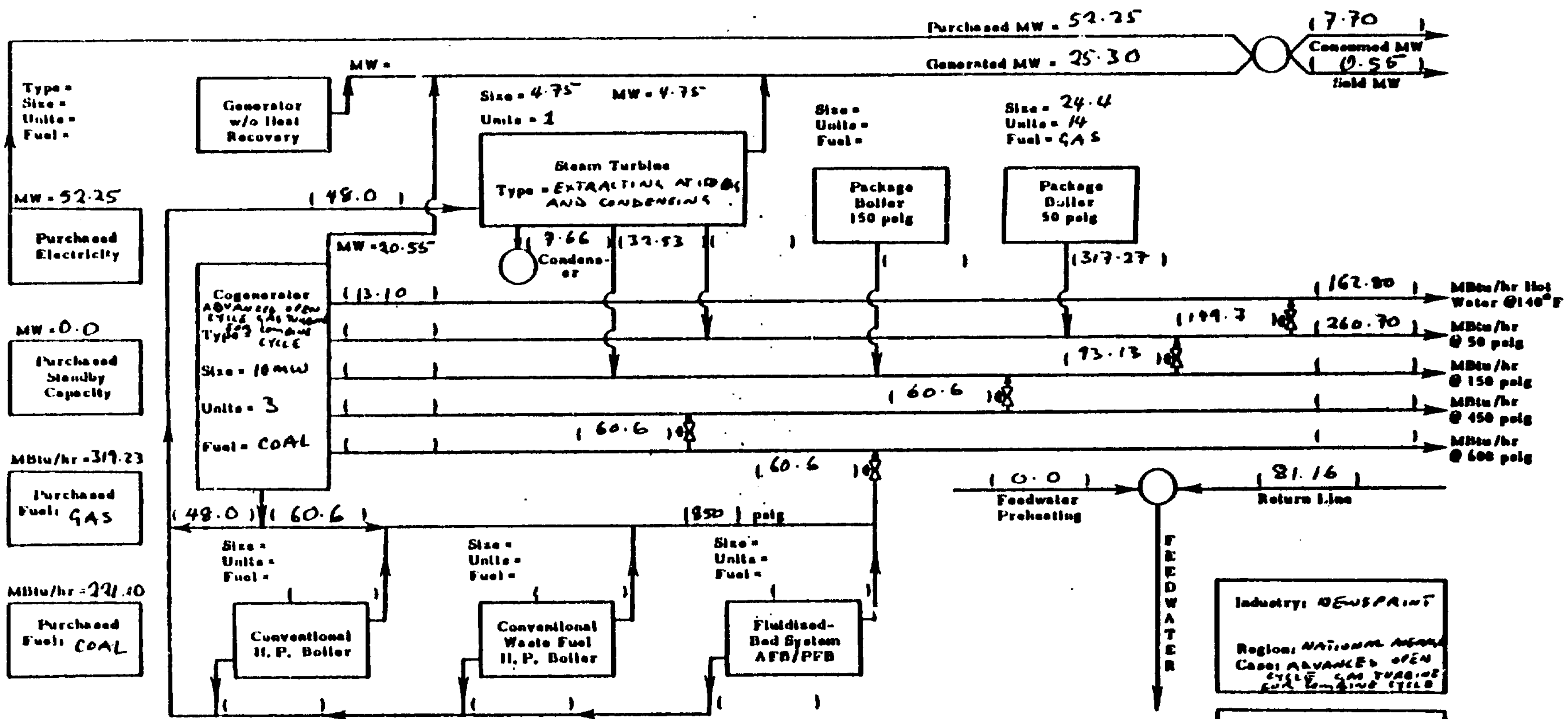
CCEQC = .1066
PCOAL = 2.12 $/MBtu
PRESIDUAL = 5.38 $/MBtu
PDISTILLATE = 6.84 $/MBtu
PGAS = 6.88 $/MBtu
PELECD = 2.43 $/kW/mo
PELECE = .029 $/kWh
PSTDBY = 2.0 $/kW/mo
PSELL = .02 $/kWh

Percent Inplant Electricity
19

Annual Plant Cost M$
30.0

Run Cost $
44

MBtu = million Btu
M$ = million dollars



Industry: NEWSPRINT

Region: NATIONAL AVERAGE
Case: ADVANCED OPEN CYCLE GAS TURBINE COMBINED CYCLE

Percent Implant Electricity
33

Annual Plant Cost M$
38.47

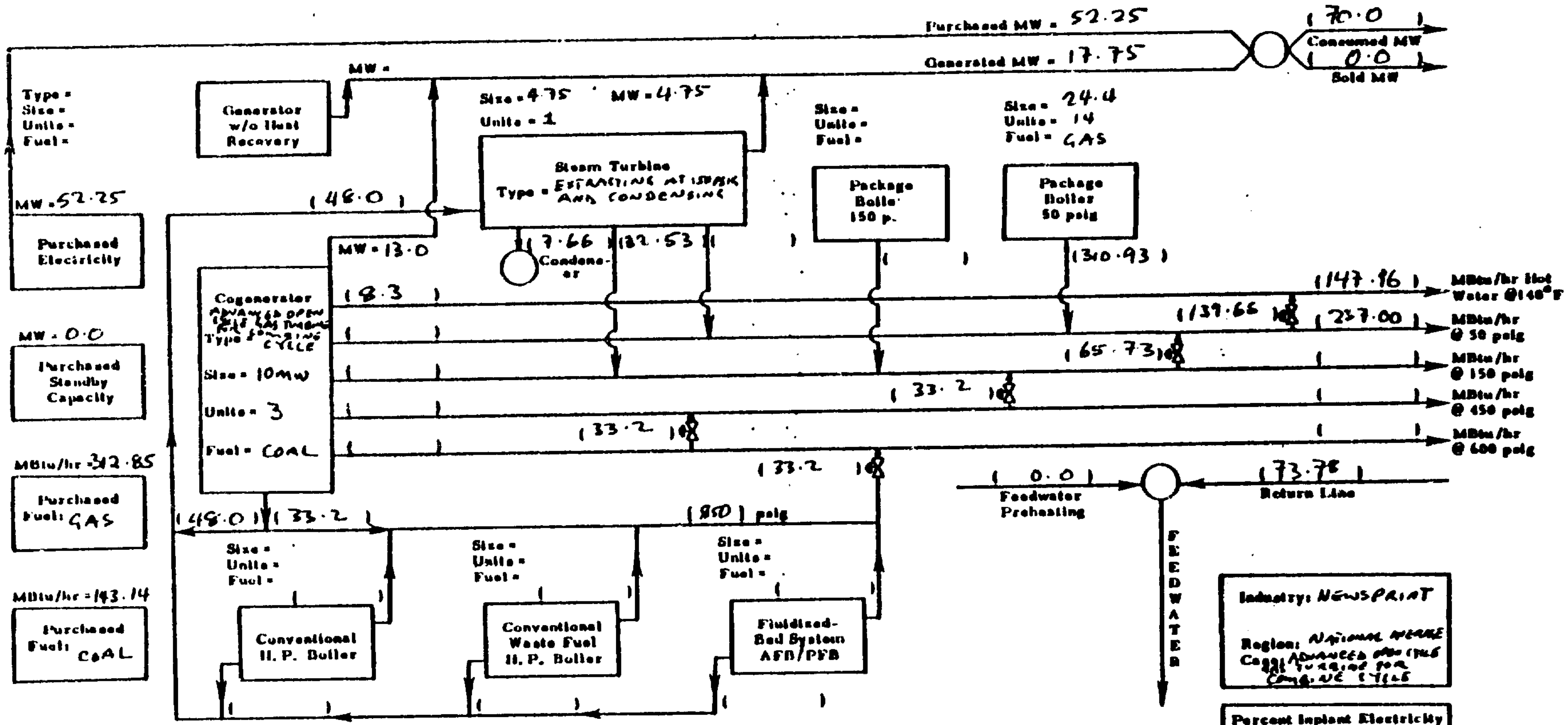
Run Cost $
63.01

MBtu = million Btu
M$ = million dollars

DEMANDS

TP	MW Electric	MBtu/hr Hot Water	MBtu/hr 50 psig	MBtu/hr 150 psig	MBtu/hr 450 psig	MBtu/hr 600 psig	MBtu/hr Waste Available	Hours
01	77.0	162.9	260.7					657.0

CCEQC	= 0.1066	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.39	$/MBtu
PDISTILLATE	= 6.94	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.83	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	02	70.0	148.0	237.0					6876.6
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	=0.1066	
PCOAL	=2.12	$/MBtu
PRESIDUAL	=5.38	$/MBtu
PDISTILLATE	=6.84	$/MBtu
PGAS	=5.28	$/MBtu
PELECD	=2.43	$/kW/mo
PELECE	=0.03	$/kWh
PSTDBY	=2.00	$/kW/mo
PSELL	=0.02	$/kWh

Industry: NEWSPRINT

Region: NATIONAL AVERAGE

Case: ADVANCED OPEN CYCLE GAS TURBINE FOR COMBINE CYCLE

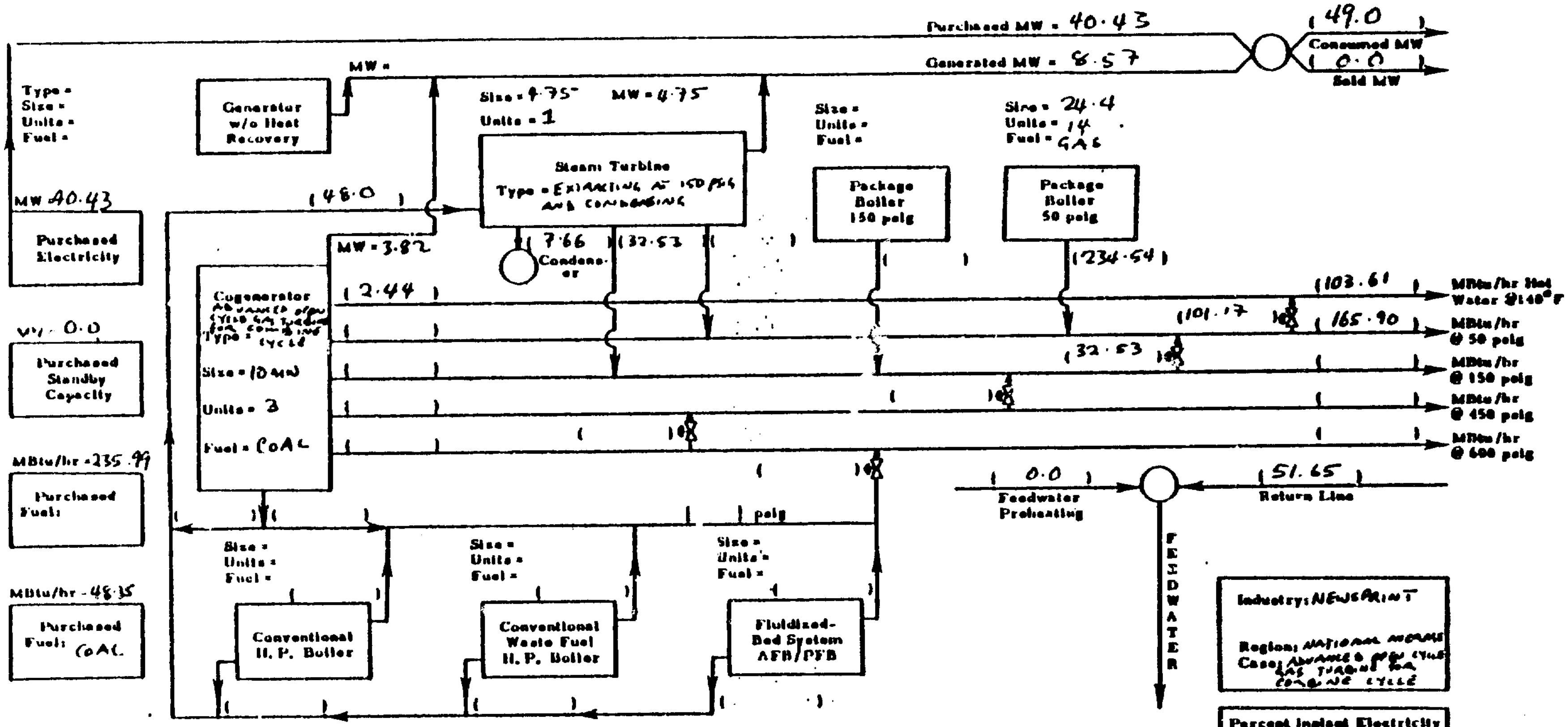
Percent Inplant Electricity
18.6

Annual Plant Cost M$
38.47

Run Cost $
63.01

MBtu = million Btu

M$ = million dollars



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	03	49	103.60	165.90					1226.90
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

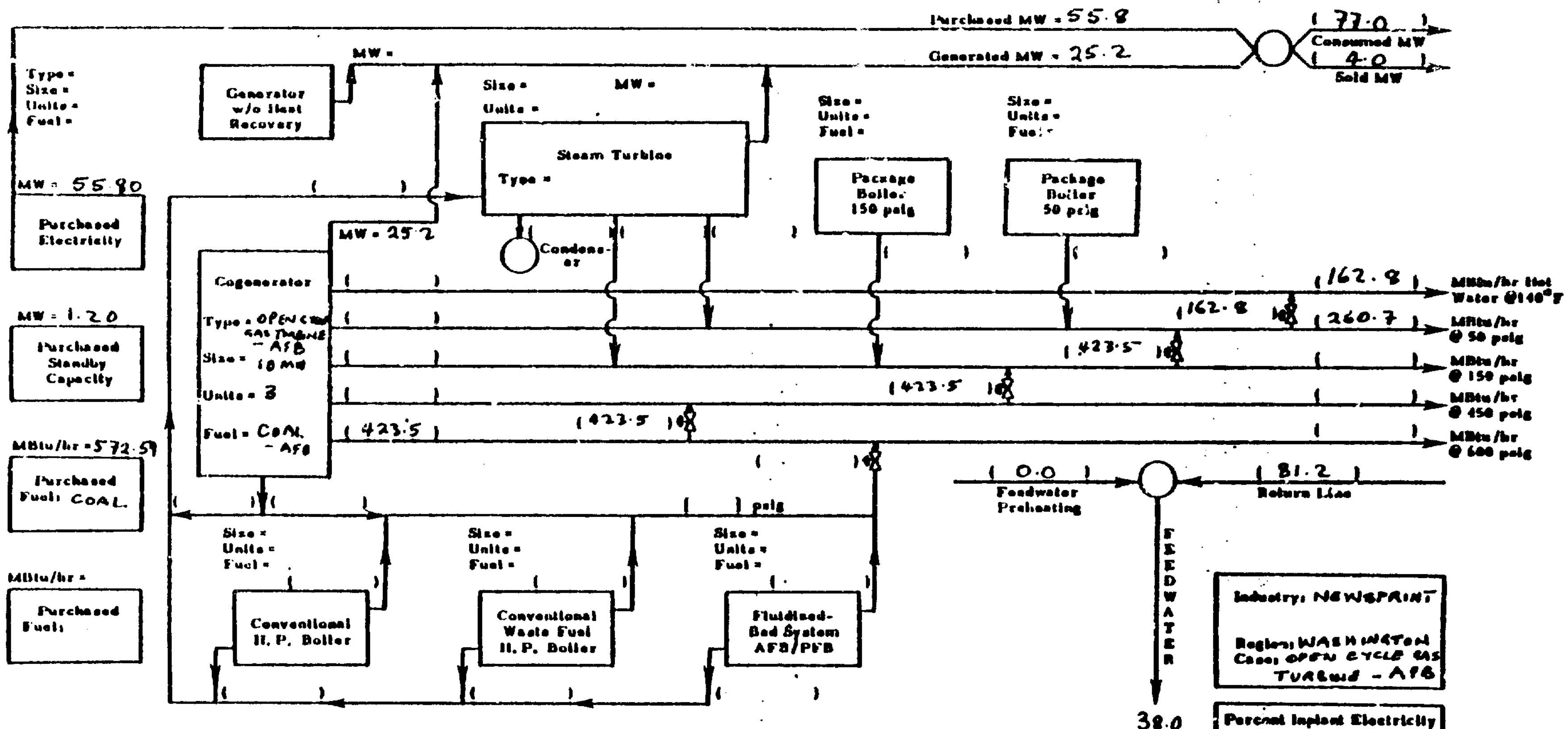
CCEQC	= 0.1066	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.38	$/MBtu
PDISTILLATE	= 6.44	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.43	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh

Percent Inplant Electricity
17.5

Annual Plant Cost M$
38.47

Run Cost $
63.01

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D	01	77	162.8	260.7					657.0
E									
M									
A									
N									
D									
S									
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

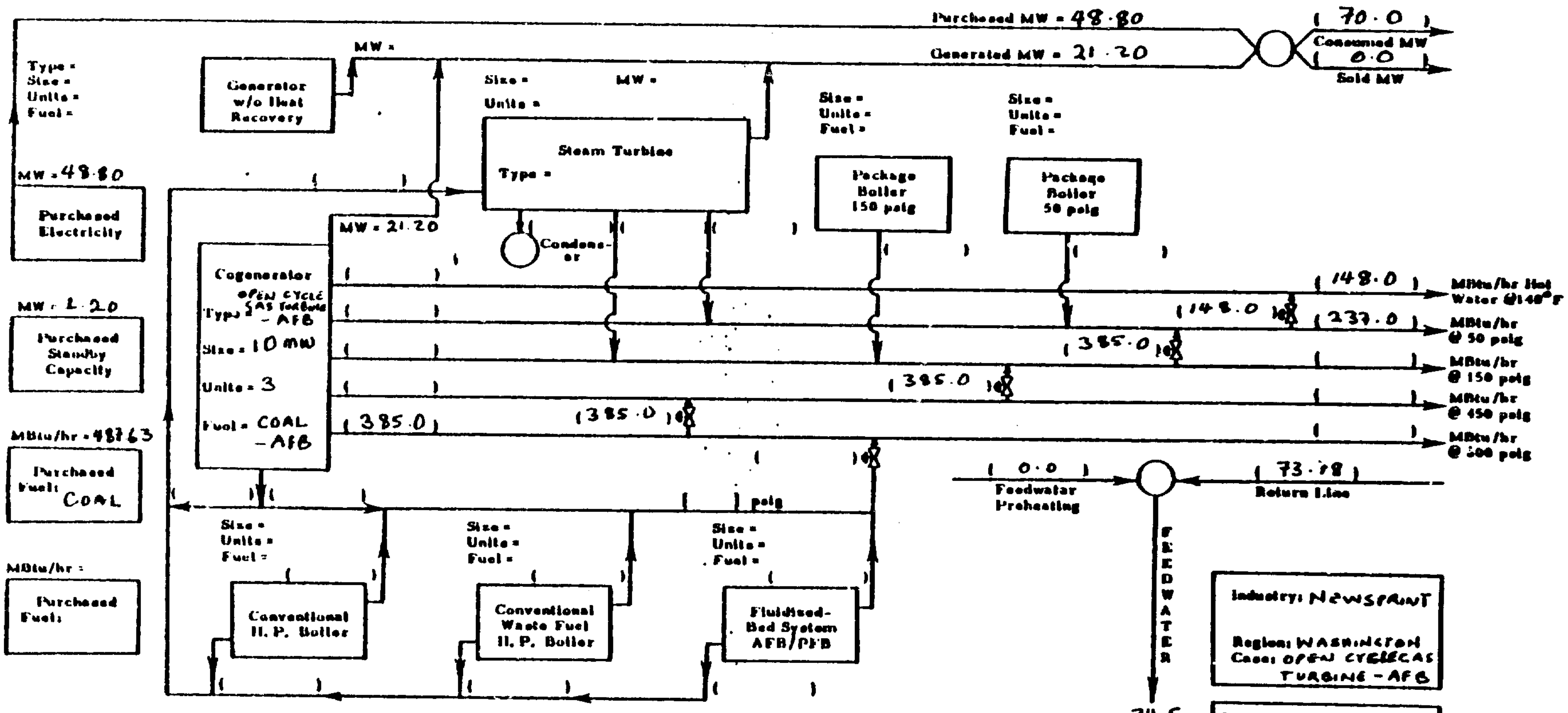
CCEQC	= .1066	
PCOAL	= 2.126	\$/MBtu
PRESIDUAL	= 4.794	\$/MBtu
PDISTILLATE	= 6.340	\$/MBtu
PGAS	= 5.806	\$/MBtu
PELECD	= 0.0	\$/kW/mo
PELECE	= .014	\$/kWh
PSTDBY	= 2.00	\$/kW/mo
PSELL	= .0085	\$/kWh

Percent Inplant Electricity
33

Annual Plant Cost M\$
21.83

Run Cost \$
23.82

MBtu = million Btu
M\$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	02	70.	148.0	237.0					6876.6
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.126	$/MBtu
PRESIDUAL	= 4.794	$/MBtu
PDISTILLATE	= 6.340	$/MBtu
PGAS	= 5.806	$/MBtu
PELECD	= 0.0	$/kW/mo
PELECE	= .014	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= .0085	$/kWh

Industry: NEWSPRINT

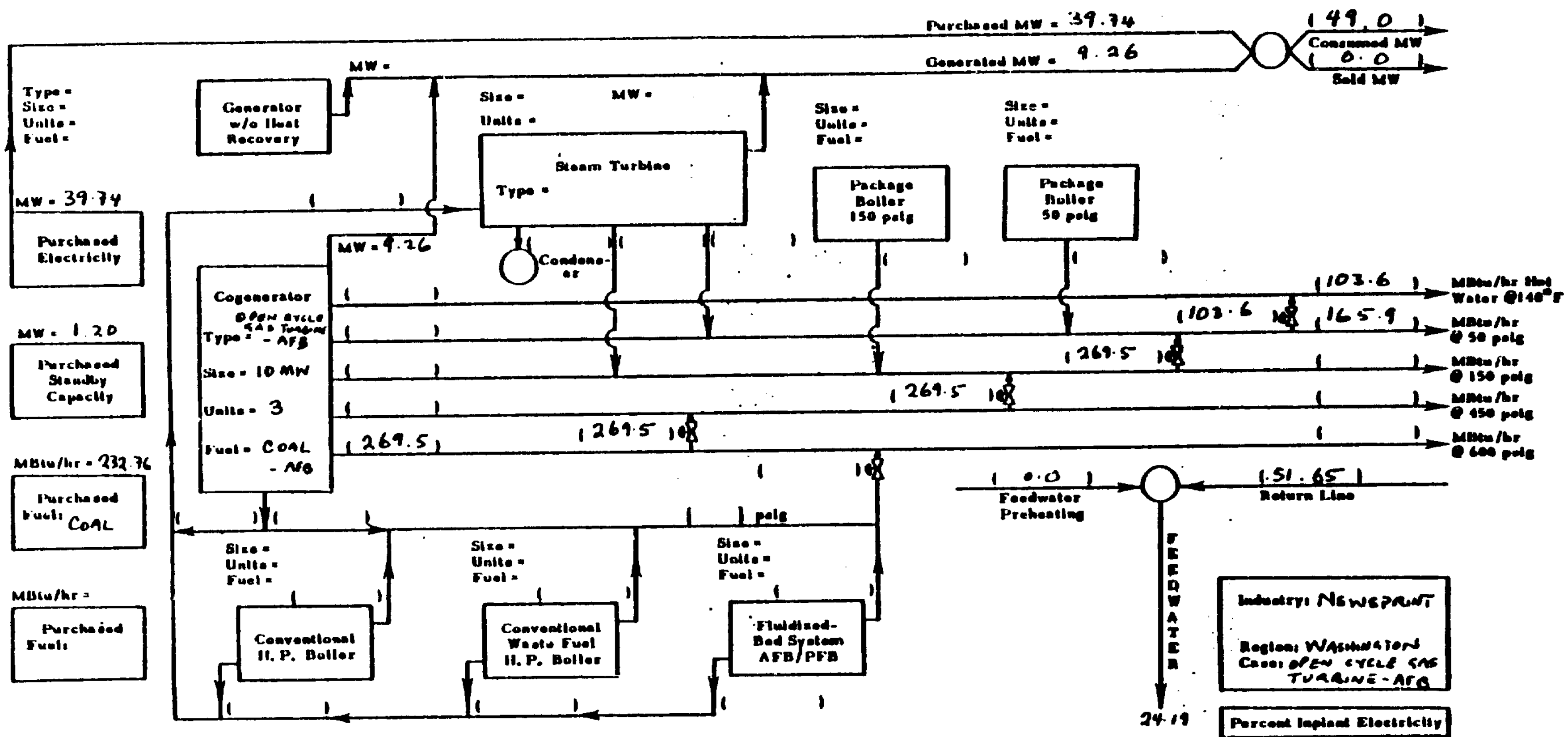
Region: WASHINGTON
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
30

Annual Plant Cost M$
21.83

Run Cost $
23.82

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D									
E									
M A N	03	49	103.6	165.9					1226.4
D S									
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.126	$/MBtu
PRESIDUAL	= 4.794	$/MBtu
PDISTILLATE	= 6.340	$/MBtu
PGAS	= 5.806	$/MBtu
PELECD	= 0.0	$/kW/mo
PELECE	= .014	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= .0065	$/kWh

Industry: NEWSPRINT

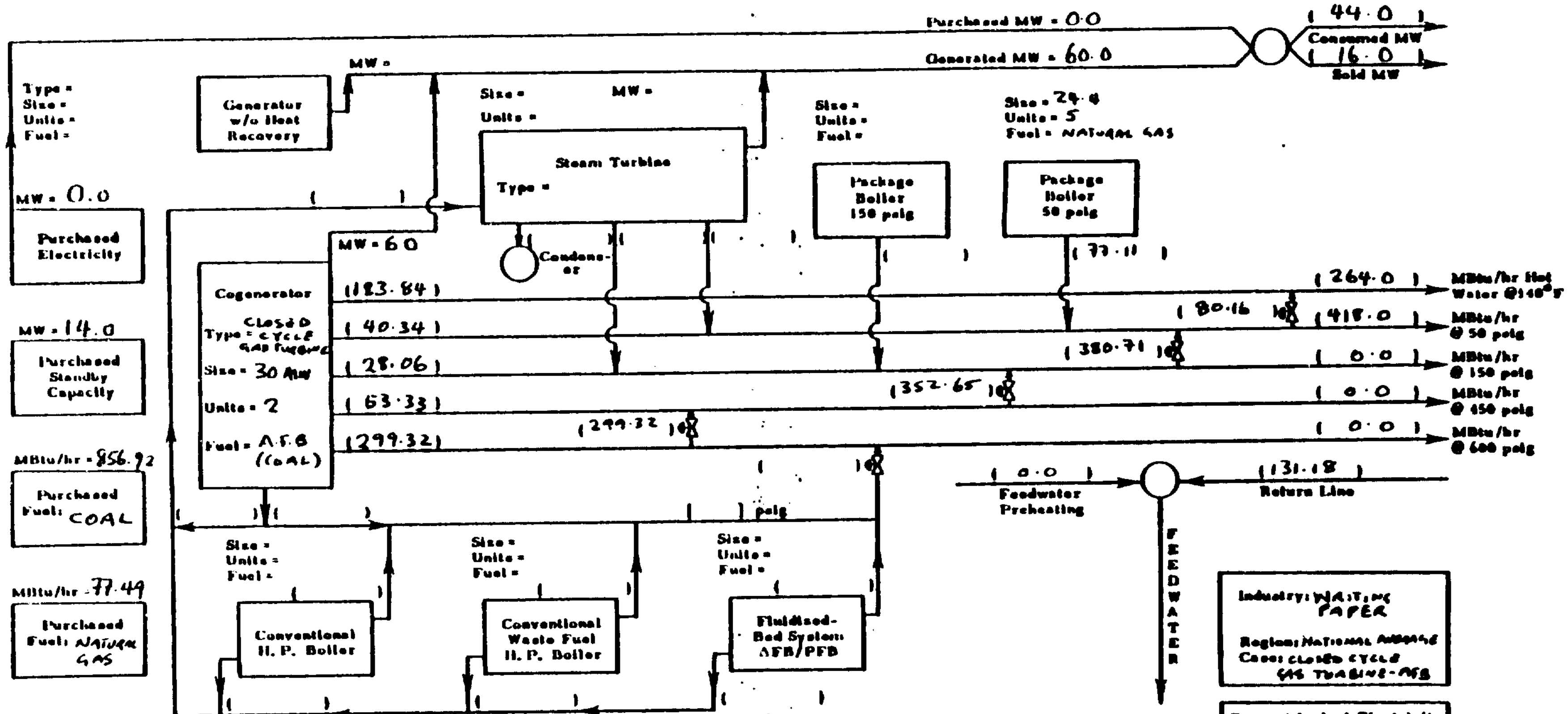
Region: WASHINGTON
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
19

Annual Plant Cost M$
21.63

Run Cost $
23.82

MBtu = million Btu
M$ = million dollars



DEMANDS

TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
1	94	264	418					1314
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

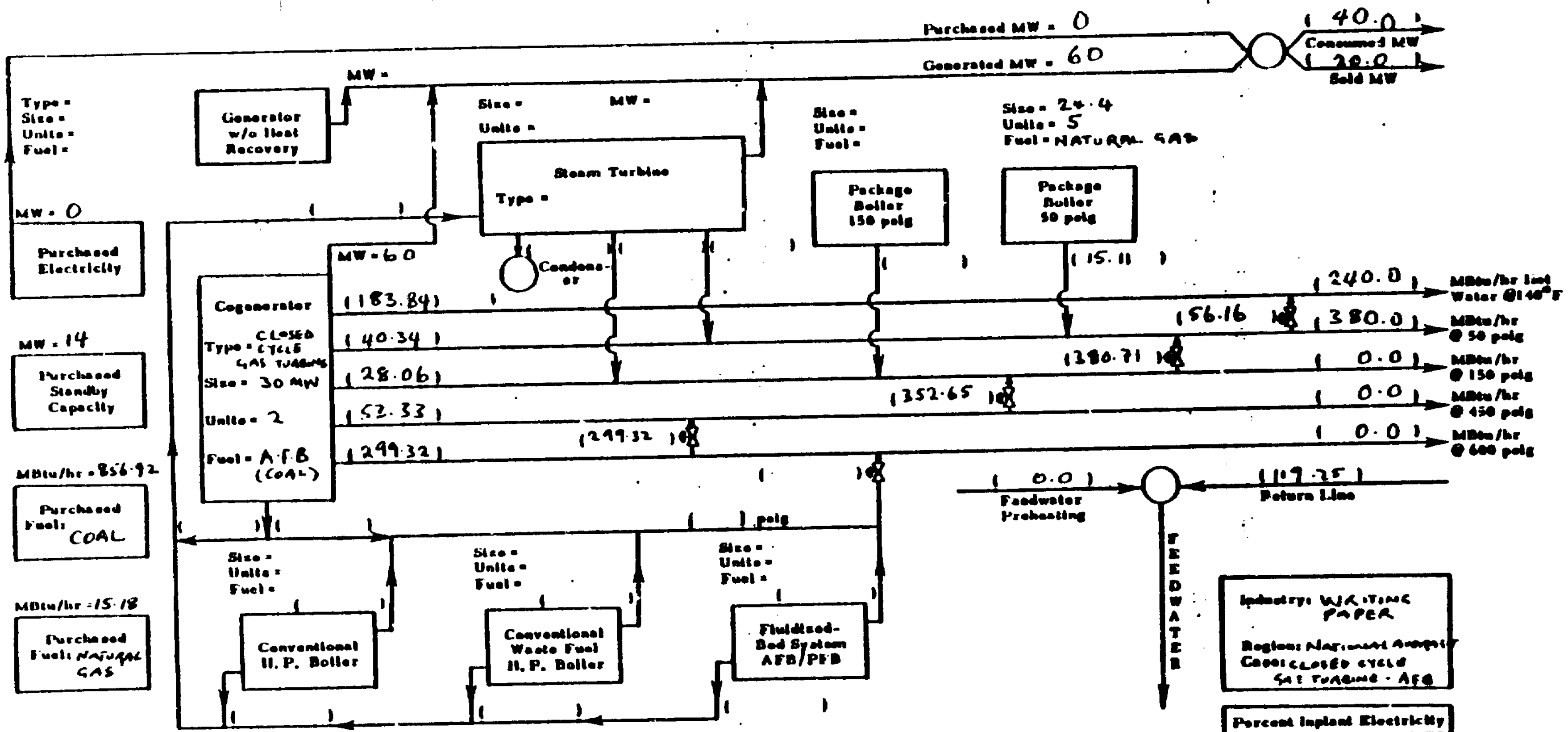
CCEQC	= 0.13	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.38	$/MBtu
PDISTILLATE	= 6.84	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.43	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh

Percent Inplant Electricity
136

Annual Plant Cost M$
23.17

Run Cost $
53.77

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	2	40	240	380					6351
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

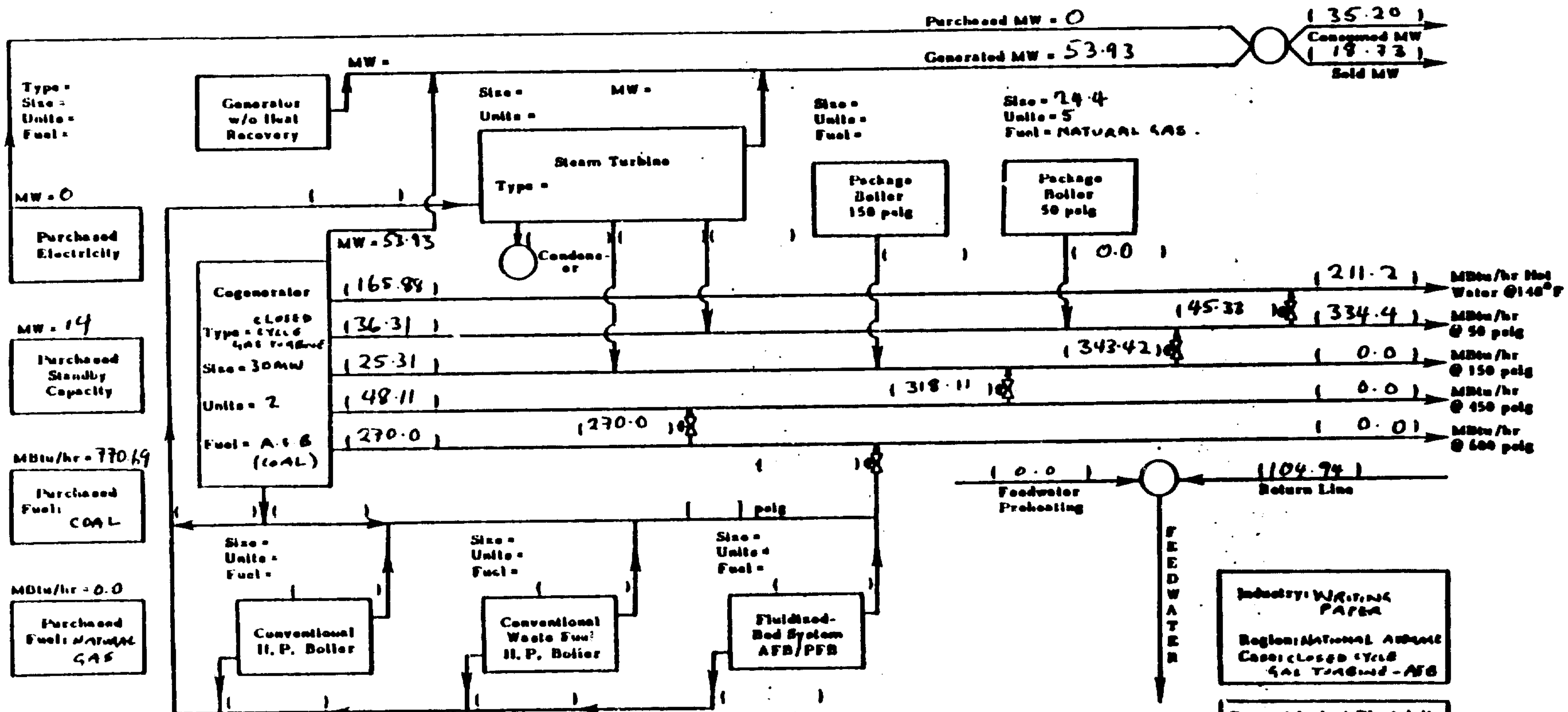
CCEQC	= 0.13	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.39	$/MBtu
PDISTILLATE	= 6.94	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.43	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh

Percent Inplant Electricity
150

Annual Plant Cost M$
23.168

Run Cost $
53.77

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	3	35.2	211.2	334.4					1095
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= 0.13	
PCOAL	= 2.12	$/MBtu
PRESIDUAL	= 5.38	$/MBtu
PDISTILLATE	= 6.94	$/MBtu
PGAS	= 5.28	$/MBtu
PELECD	= 2.93	$/kW/mo
PELECE	= 0.03	$/kWh
PSTDBY	= 2.00	$/kW/mo
PSELL	= 0.02	$/kWh

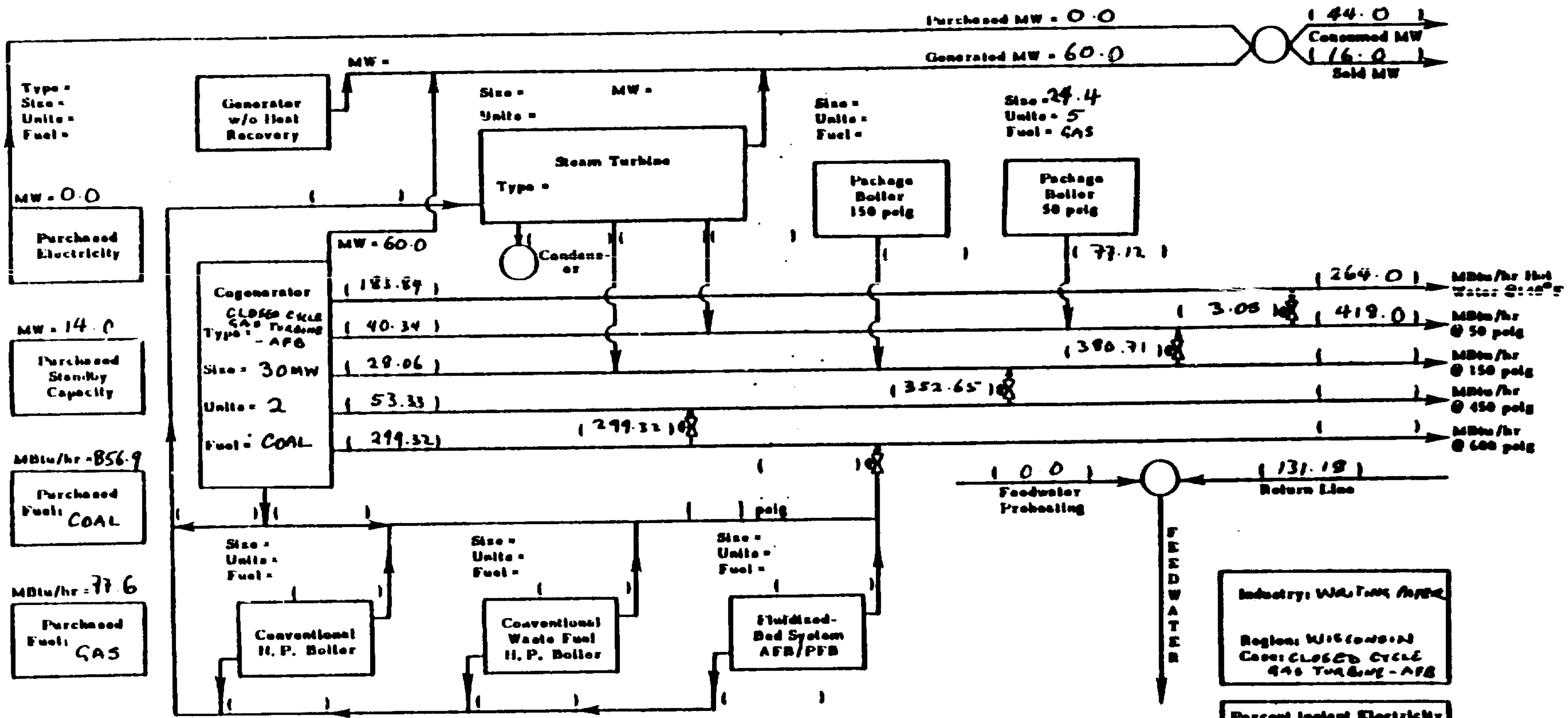
Percent Inplant Electricity: 153

Annual Plant Cost M$: 23.168

Run Cost $: 53.77

MBtu = million Btu

M$ = million dollars



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	01	44	264.0	418.0					1314
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

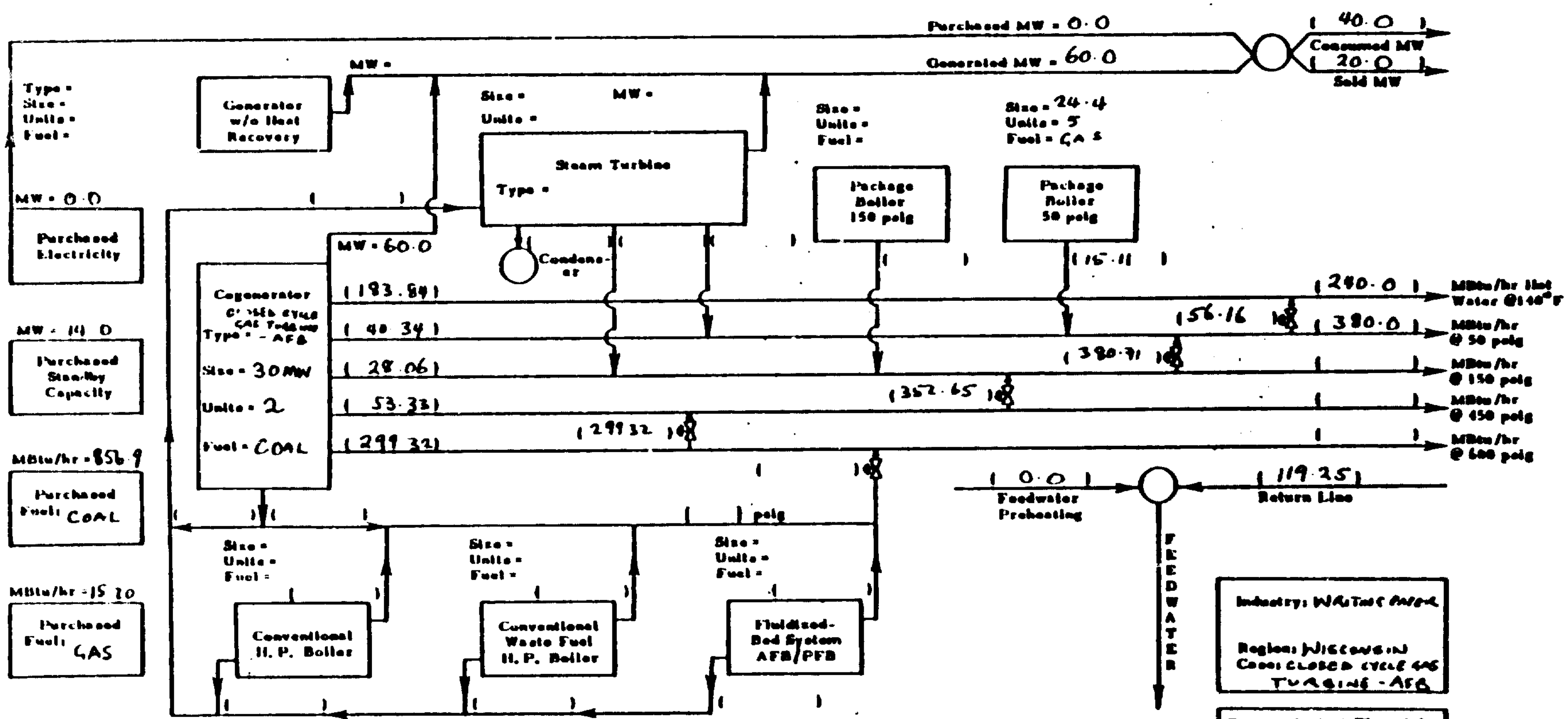
CCEQC	= .1066	
PCOAL	= 2.038	$/MBtu
PRESIDUAL	= 5.423	$/MBtu
PDISTILLATE	= 6.890	$/MBtu
PGAS	= 6.515	$/MBtu
PELECD	= 9.248	$/kW/mo
PELECE	= .029	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .021	$/kWh

Percent Inplant Electricity
136.4

Annual Plant Cost M$
22.76

Run Cost $
28.83

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS	82	40.0	240.0	380.0					6351.0
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.038	$/MBtu
PRESIDUAL	= 5.423	$/MBtu
PDISTILLATE	= 6.490	$/MBtu
PGAS	= 6.665	$/MBtu
PELECD	= 4.248	$/kW/mo
PELECE	= .028	$/kWh
PSTDBY	= 2.080	$/kW/mo
PSELL	= .021	$/kWh

Industry: WRITING PAPER

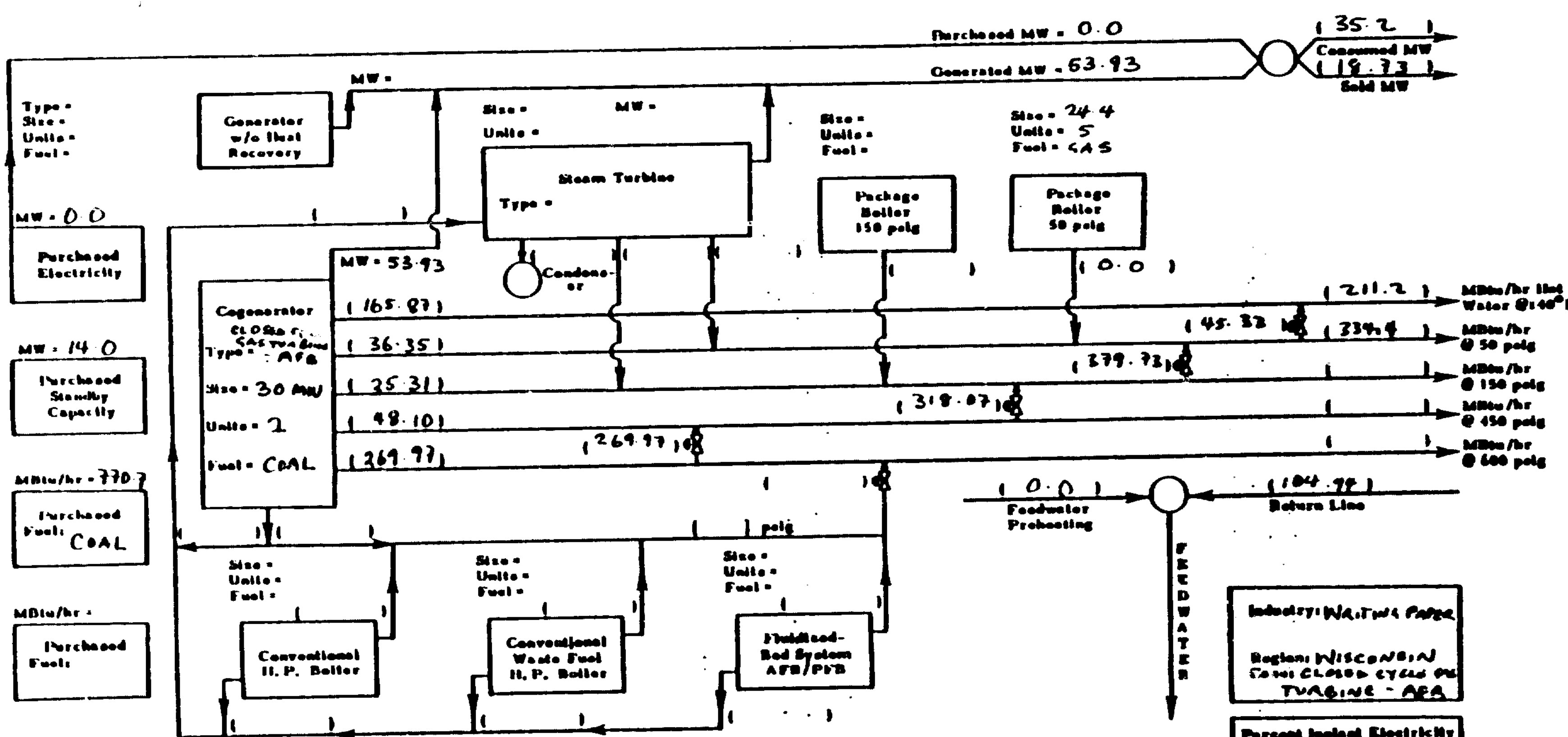
Region: WISCONSIN
Case: CLOSED CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
150

Annual Plant Cost M$
22.76

Run Cost $
28.83

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	03	35.2	211.2	334.4					1015.0
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.036	$/MBtu
PRESIDUAL	= 5.023	$/MBtu
PDISTILLATE	= 6.880	$/MBtu
PGAS	= 6.565	$/MBtu
PELECD	= 4.248	$/kW/mo
PELECE	= .028	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .021	$/kWh

Industry: WRITING PAPER

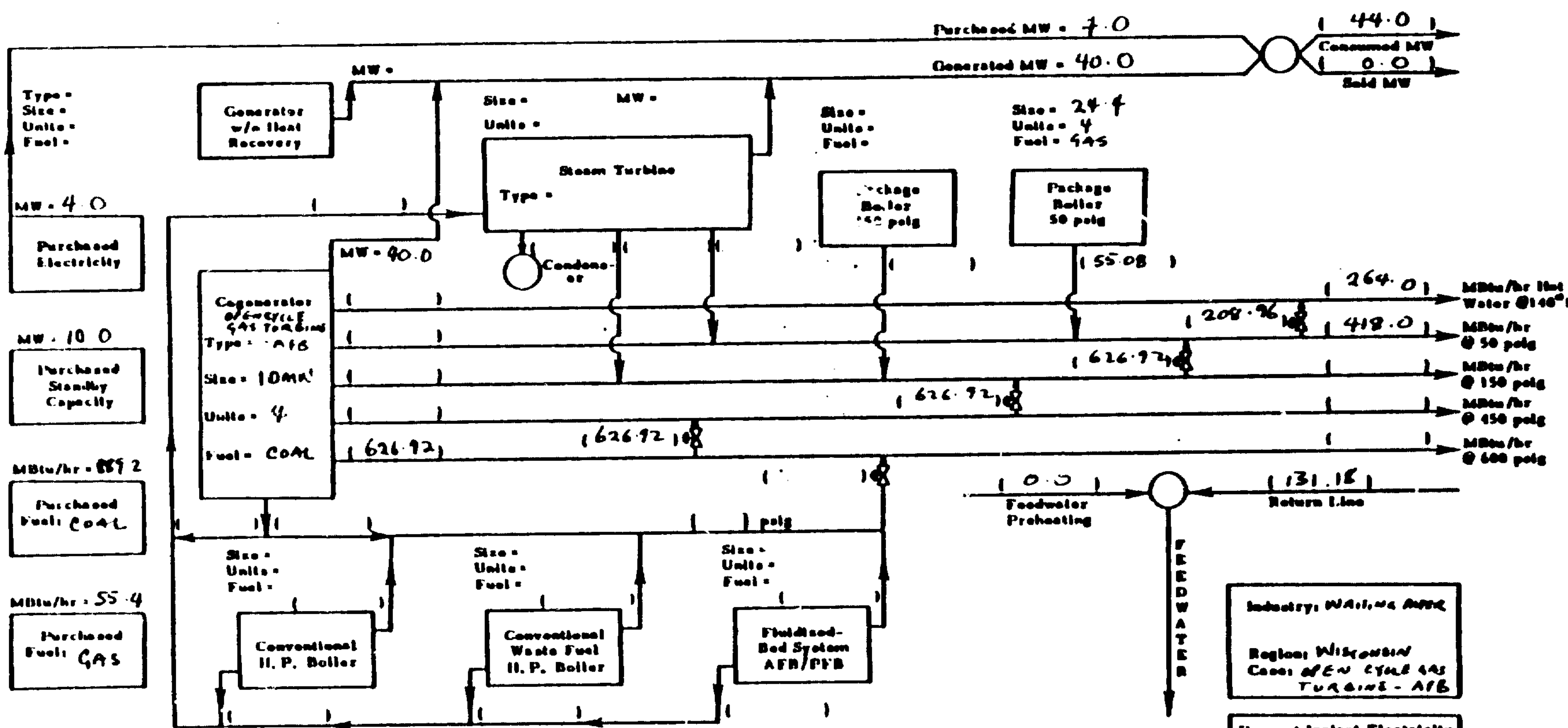
Region: WISCONSIN
Case: CLOSED CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
153

Annual Plant Cost M$
22.76

Run Cost $
28.83

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS	01	44.0	264.0	418.0					1314
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.039	$/MBtu
PRESIDUAL	= 5.023	$/MBtu
PDISTILLATE	= 6.680	$/MBtu
PGAS	= 6.565	$/MBtu
PELECD	= 4.249	$/kW/mo
PELECE	= .028	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .021	$/kWh

Industry: WALLING PAPER

Region: WISCONSIN

Case: OPEN CYCLE GAS TURBINE - AFB

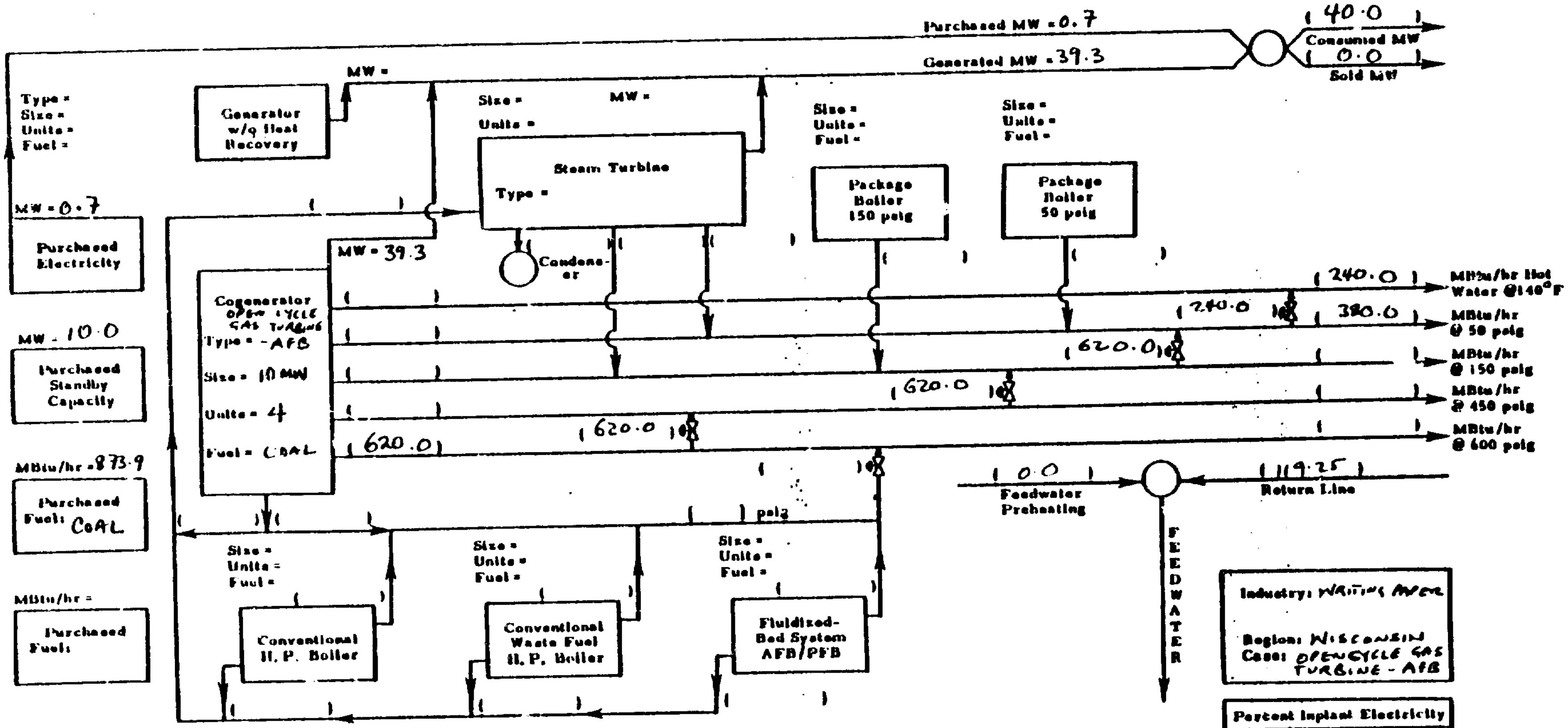
Percent Inplant Electricity
91

Annual Plant Cost M$
26.51

Run Cost $
36.54

MBtu = million Btu

M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D E M A N D S									
	02	40.0	240.0	380.0					6351.
			—						
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.028	$/MBtu
PRESIDUAL	= 5.423	$/MBtu
PDISTILLATE	= 6.880	$/MBtu
PGAS	= 6.565	$/MBtu
PELECD	= 4.249	$/kW/mo
PELECE	= .028	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .021	$/kWh

Industry: WRITING PAPER

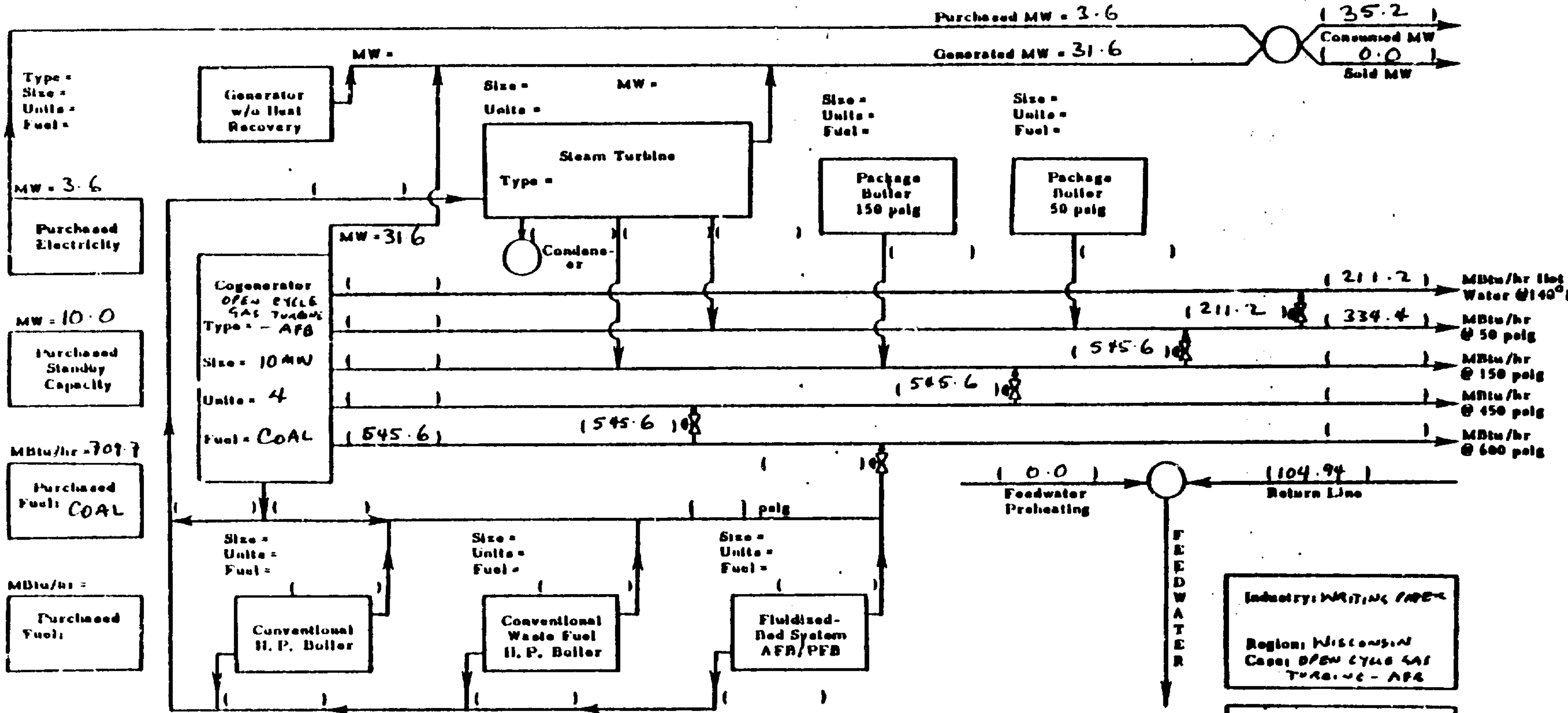
Region: WISCONSIN
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
98.3

Annual Plant Cost M$
26.51

Run Cost $
36.54

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS									
	03	35.2	211.2	334.4					1095
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

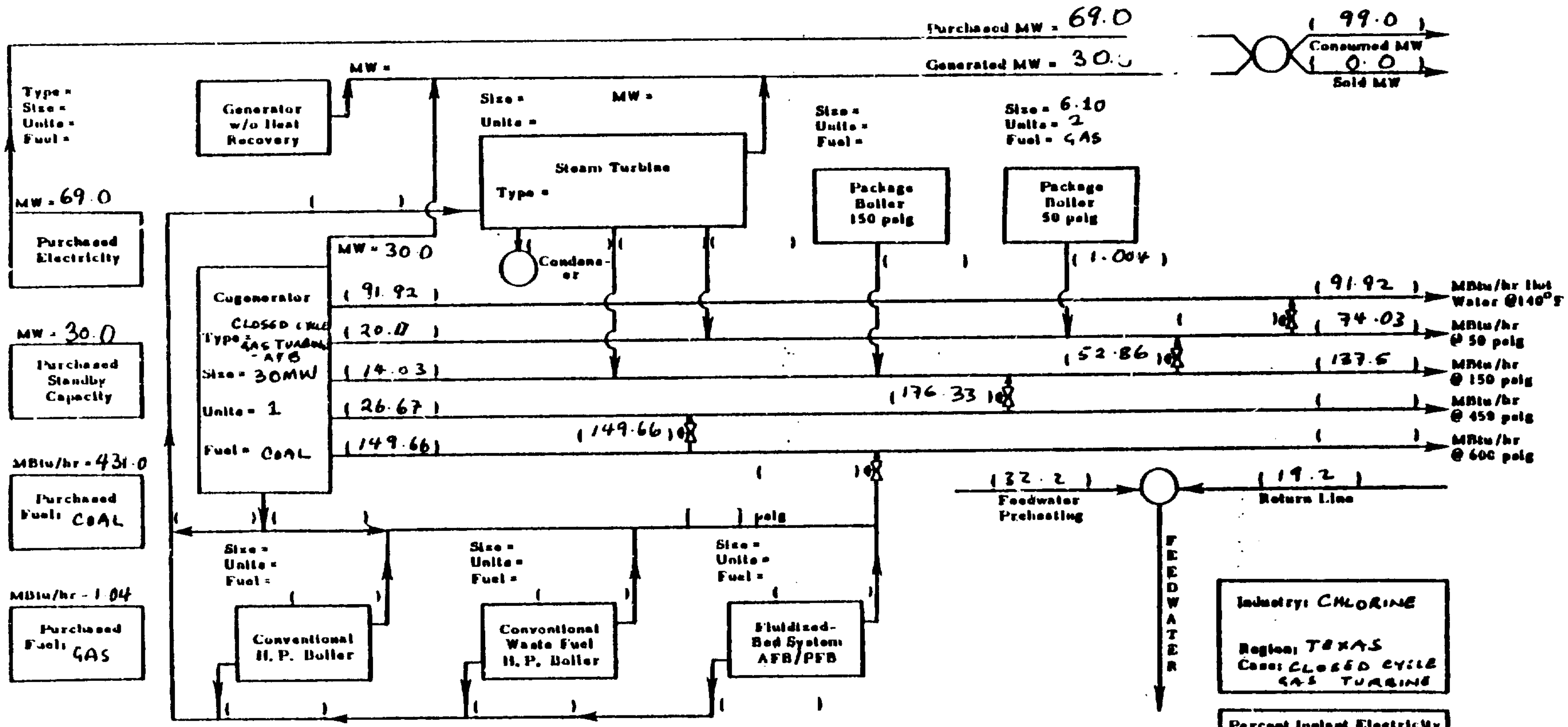
CCEQC	= .1066	
PCOAL	= 2.038	$/MBtu
PRESIDUAL	= 5.423	$/MBtu
PDISTILLATE	= 6.980	$/MBtu
PGAS	= 6.565	$/MBtu
PELECD	= 4.249	$/kW/mo
PELECE	= .028	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .021	$/kWh

Percent Inplant Electricity
90

Annual Plant Cost M$
26.51

Run Cost $
36.54

MBtu = million Btu
M$ = million dollars



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
DEMANDS	01	99		74.03	137.5				876
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC = .1066
PCOAL = 2.056 $/MBtu
PRESIDUAL = 5.381 $/MBtu
PDISTILLATE = 6.694 $/MBtu
PGAS = 4.440 $/MBtu
PELECD = 1.789 $/kW/mo
PELECE = .036 $/kWh
PSTDBY = 2.000 $/kW/mo
PSELL = .023 $/kWh

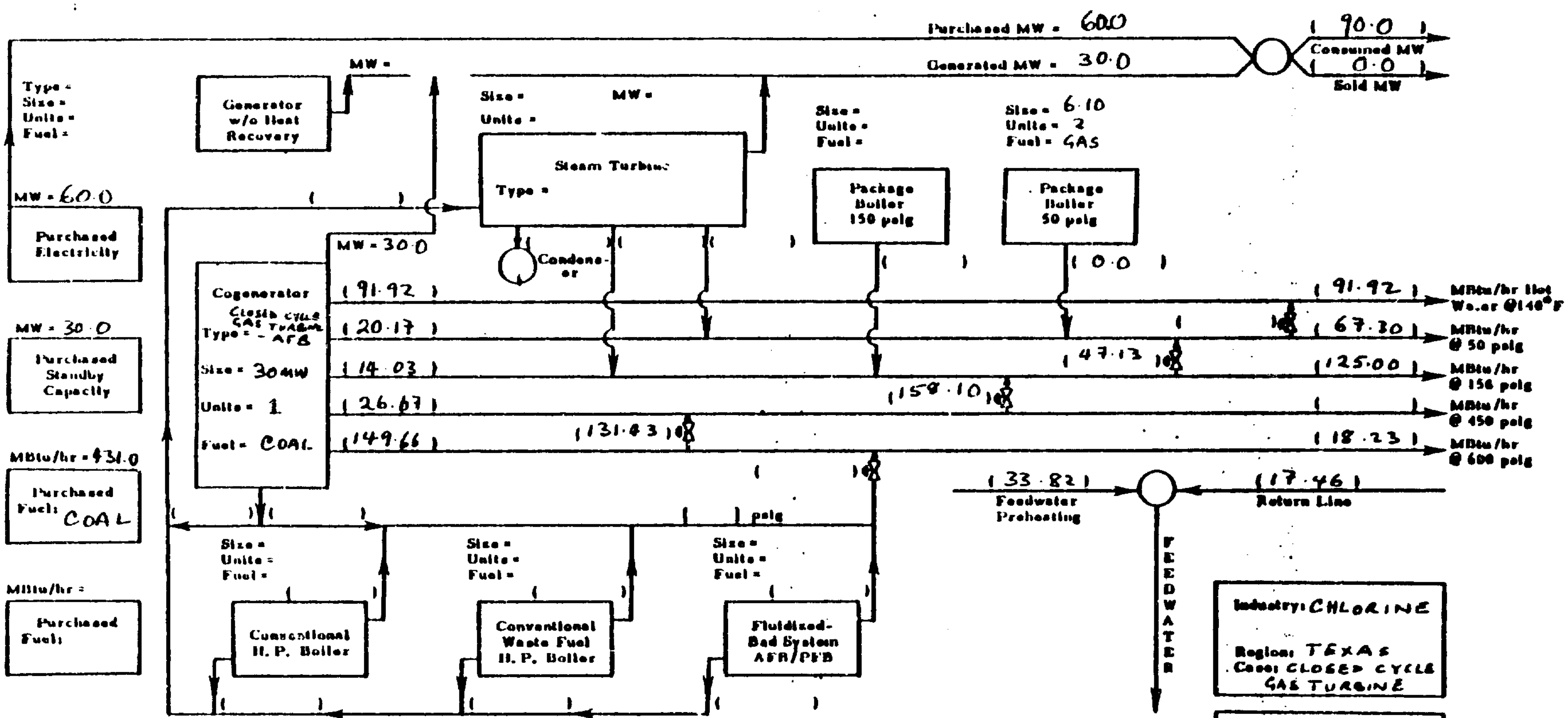
Industry: CHLORINE
Region: TEXAS
Case: CLOSED CYCLE GAS TURBINE

Percent Inplant Electricity
30

Annual Plant Cost M$
32.73

Run Cost $
23.24

MBtu = million Btu
M$ = million dollars



Industry: CHLORINE

Region: TEXAS
Case: CLOSED CYCLE GAS TURBINE

Percent Inplant Electricity
33.33

Annual Plant Cost M$
32.73

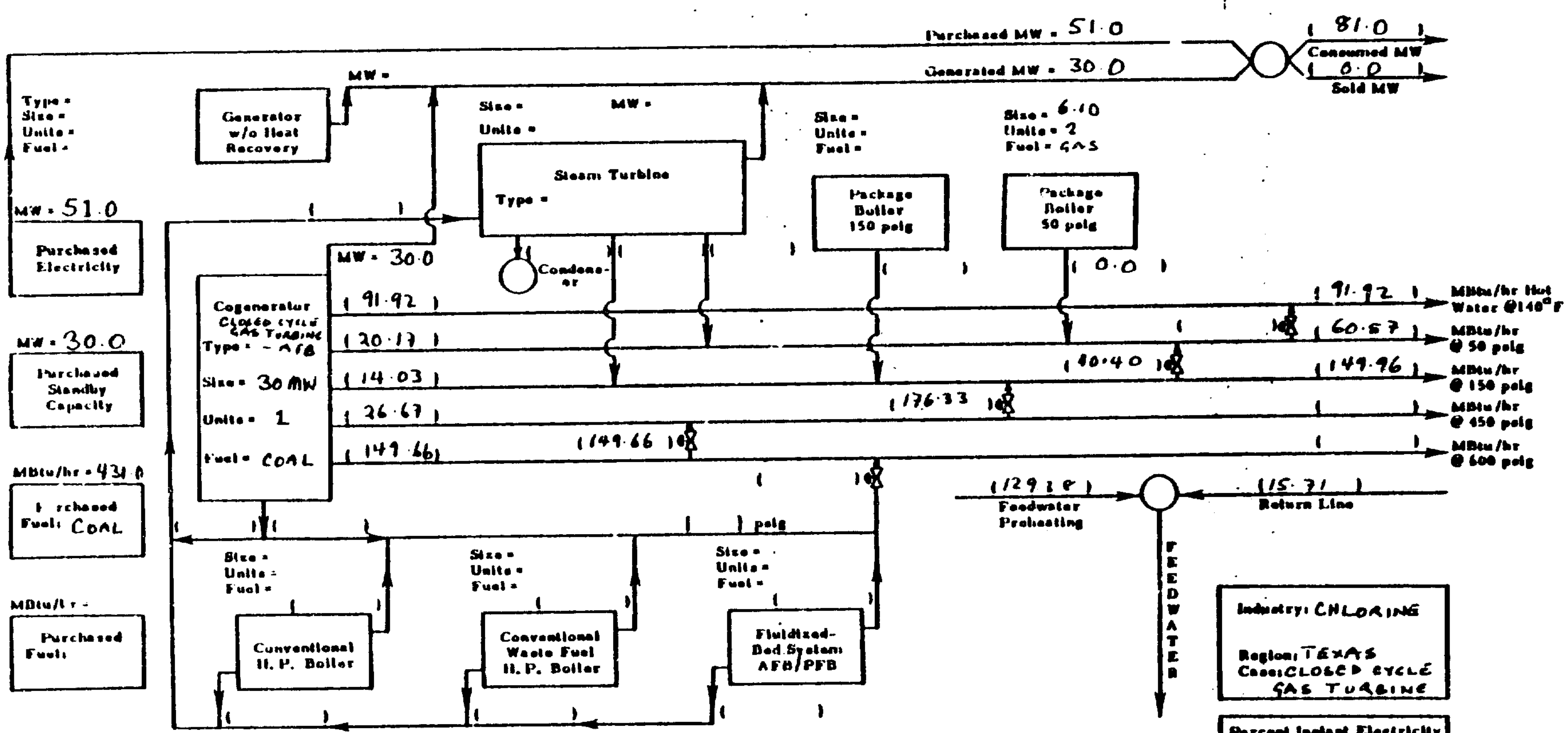
Run Cost $
23.24

MBtu = million Btu
M$ = million dollars

DEMANDS

TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	
02	90.0		67.3	125.0				4380.0

CCEQC	= .1066	
PCOAL	= 2.056	$/MBtu
PRESIDUAL	= 5.391	$/MBtu
PDISTILLATE	= 6.894	$/MBtu
PGAS	= 4.440	$/MBtu
PELECD	= 1.780	$/kW/mo
PELECE	= .036	$/kWh
PSTDBY	= 1.000	$/kW/mo
PSELL	= .023	$/kWh



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
D									
E									
M									
A N D	03	81		60.57	112.5				3504
S									
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.056	$/MBtu
PRESIDUAL	= 5.381	$/MBtu
PDISTILLATE	= 6.894	$/MBtu
PGAS	= 4.440	$/MBtu
PELECD	= 1.780	$/kW/mo
PELECE	= .036	$/kWh
PSTDBY	= 2.070	$/kW/mo
PSELL	= .023	$/kWh

Industry: CHLORINE

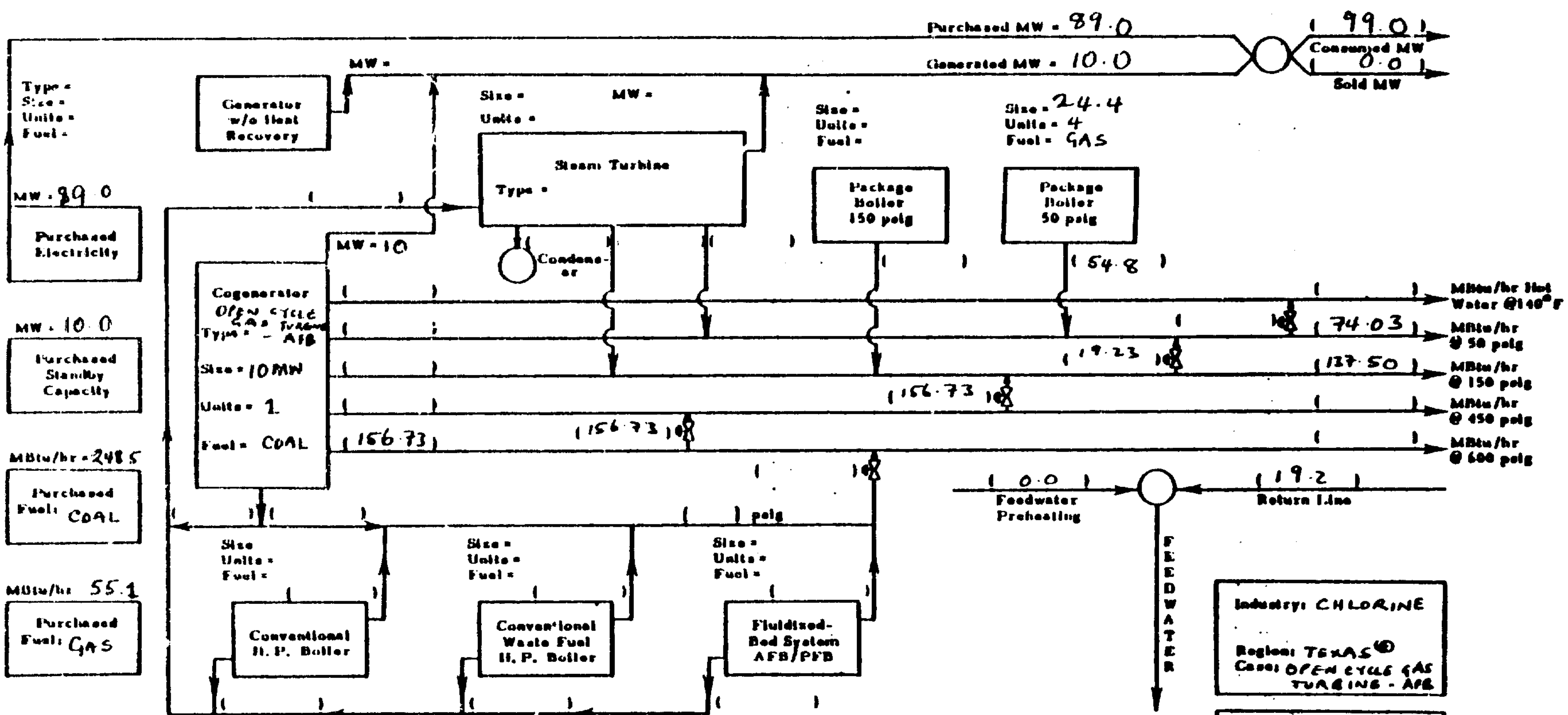
Region: TEXAS
Case: CLOSED CYCLE GAS TURBINE

Percent Inplant Electricity
37.0

Annual Plant Cost M$
32.73

Run Cost $
23.24

MBtu = million Btu
M$ = million dollars



DEMANDS

TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
01	99.0		74.03	137.5				876
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

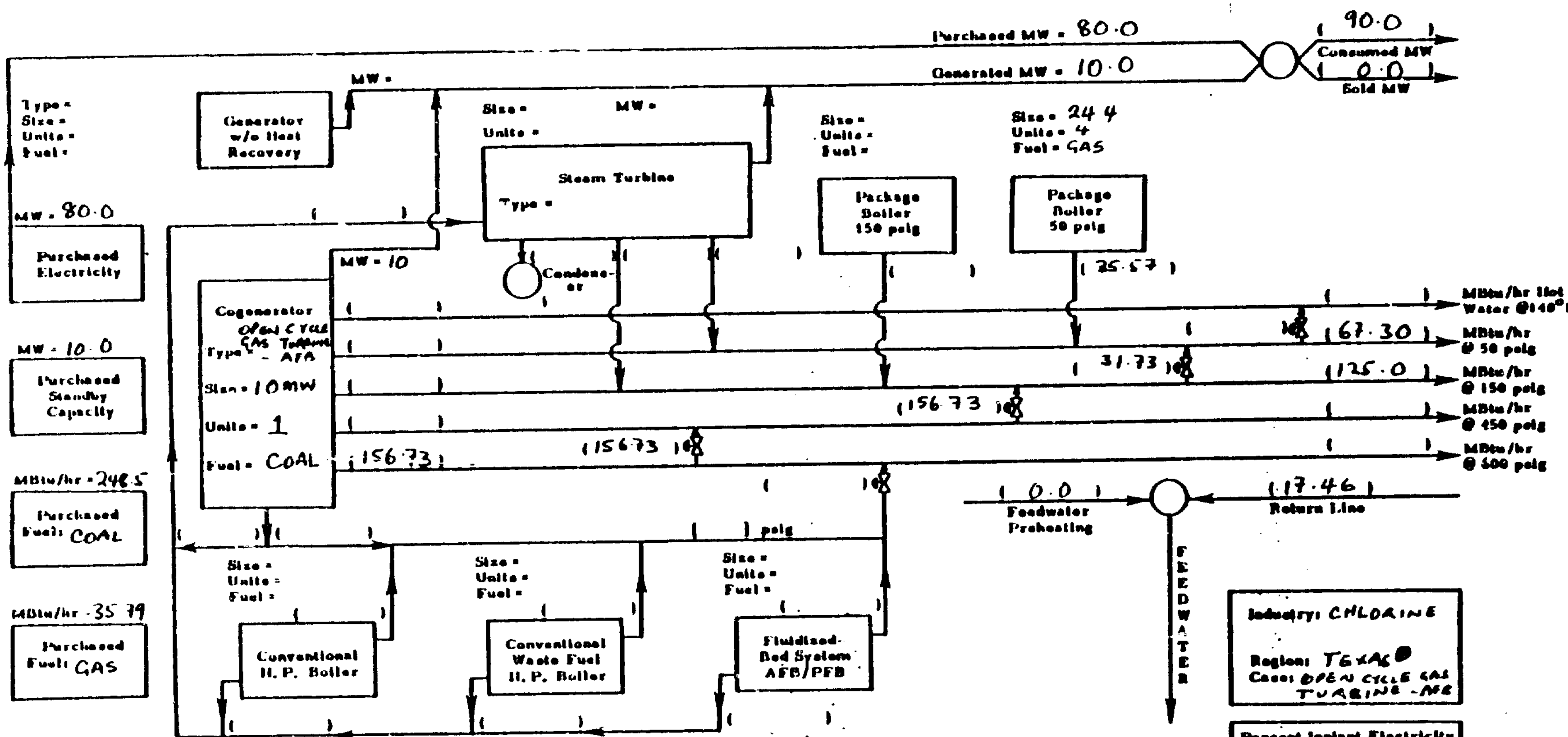
CCEQC	= .1066	
PCOAL	= 2.058	$/MBtu
PRESIDUAL	= 5.381	$/MBtu
PDISTILLATE	= 6.894	$/MBtu
PGAS	= 4.440	$/MBtu
PELECD	= 1.789	$/kW/mo
PELECE	= .036	$/kWh
PSTDBY	= 2.080	$/kW/mo
PSELL	= .023	$/kWh

Percent Inplant Electricity
10

Annual Plant Cost M$
34.690

Run Cost $
22.66

MBtu = million Btu
M$ = million dollars
(*) SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN



Industry: CHLORINE

Region: TEXAS ⓐ
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
11

Annual Plant Cost M$
34.690

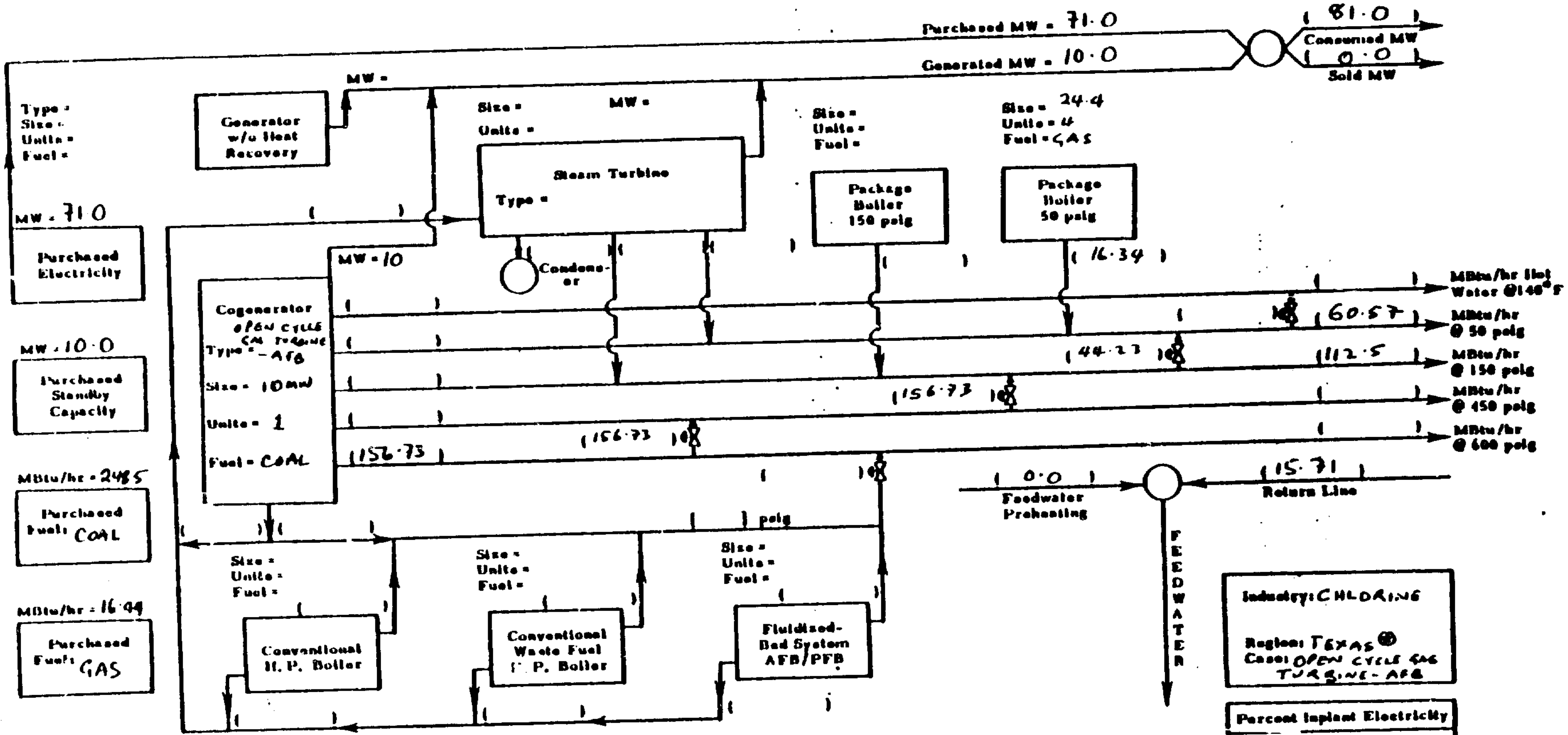
Run Cost $
22.66

MBtu = million Btu
M$ = million dollars
ⓐ SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN

DEMANDS

TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
02	90.0		67.30	125.00				4380.0
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC = .1066
PCOAL = 2.056 $/MBtu
PRESIDUAL = 5.381 $/MBtu
PDISTILLATE = 6.994 $/MBtu
PGAS = 4.440 $/MBtu
PELECD = 1.789 $/kW/mo
PELECE = .036 $/kWh
PSTDBY = 2.000 $/kW/mo
PSELL = .023 $/kWh



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	03	81		60.57	112.5				3504
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

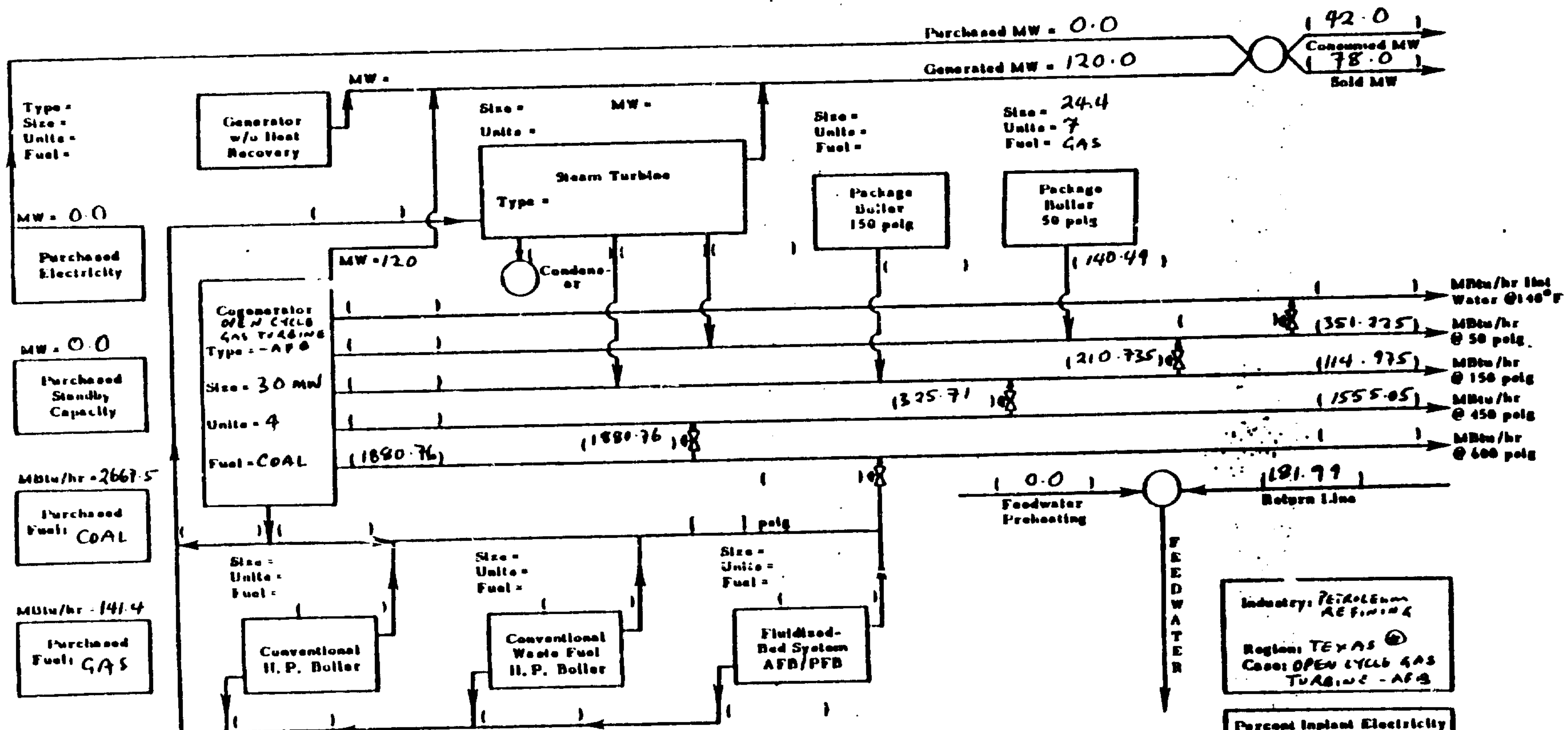
CCEQC = .1066
PCOAL = 2.066 \$/MBtu
PRESIDUAL = 5.381 \$/MBtu
PDISTILLATE = 6.694 \$/MBtu
PGAS = 4.440 \$/MBtu
PELECD = 1.789 \$/kW/mo
PELECE = .036 \$/kWh
PSTDBY = 4.000 \$/kW/mo
PSELL = .023 \$/kWh

Percent Inplant Electricity
12

Annual Plant Cost M\$
34.69

Run Cost \$
22.66

MBtu = million Btu
M\$ = million dollars
(B) SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN



DEMANDS TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
01			351.25	114.975	1555.05			836.28
	Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.056	$/MBtu
PRESIDUAL	= 5.381	$/MBtu
PDISTILLATE	= 6.894	$/MBtu
PGAS	= 4.440	$/MBtu
PELECD	= 1.789	$/kW/mo
PELECE	= .036	$/kWh
PSTDBY	= 2.000	$/kW/mo
PSELL	= .023	$/kWh

Industry: PETROLEUM REFINING

Region: TEXAS Ⓐ
Case: OPEN CYCLE GAS TURBINE - AFB

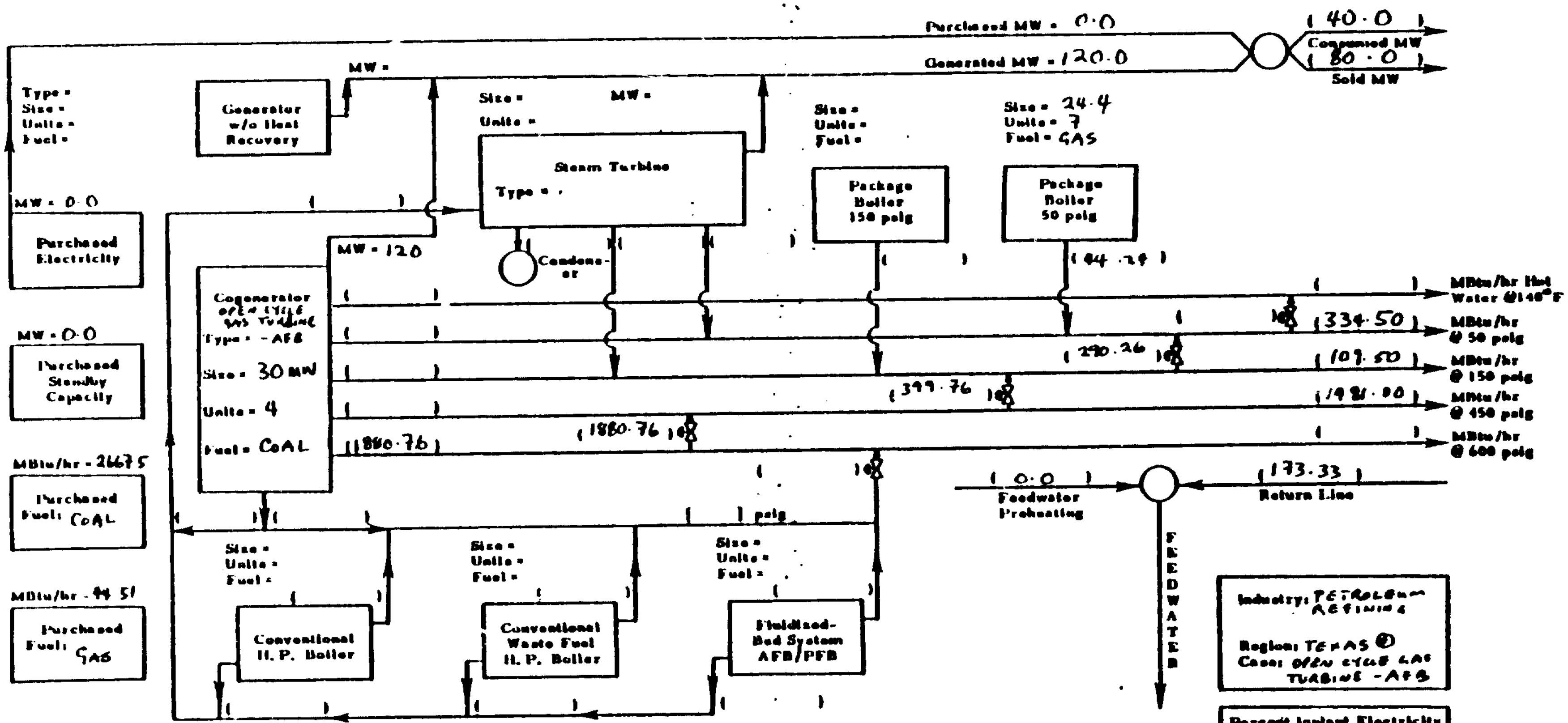
Percent Inplant Electricity
28.7

Annual Plant Cost M$
56.64

Run Cost $
28.46

MBtu = million Btu
M$ = million dollars

Ⓐ SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN



Industry: PETROLEUM REFINING

Region: TEXAS ⓔ
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
300

Annual Plant Cost M$
56.64

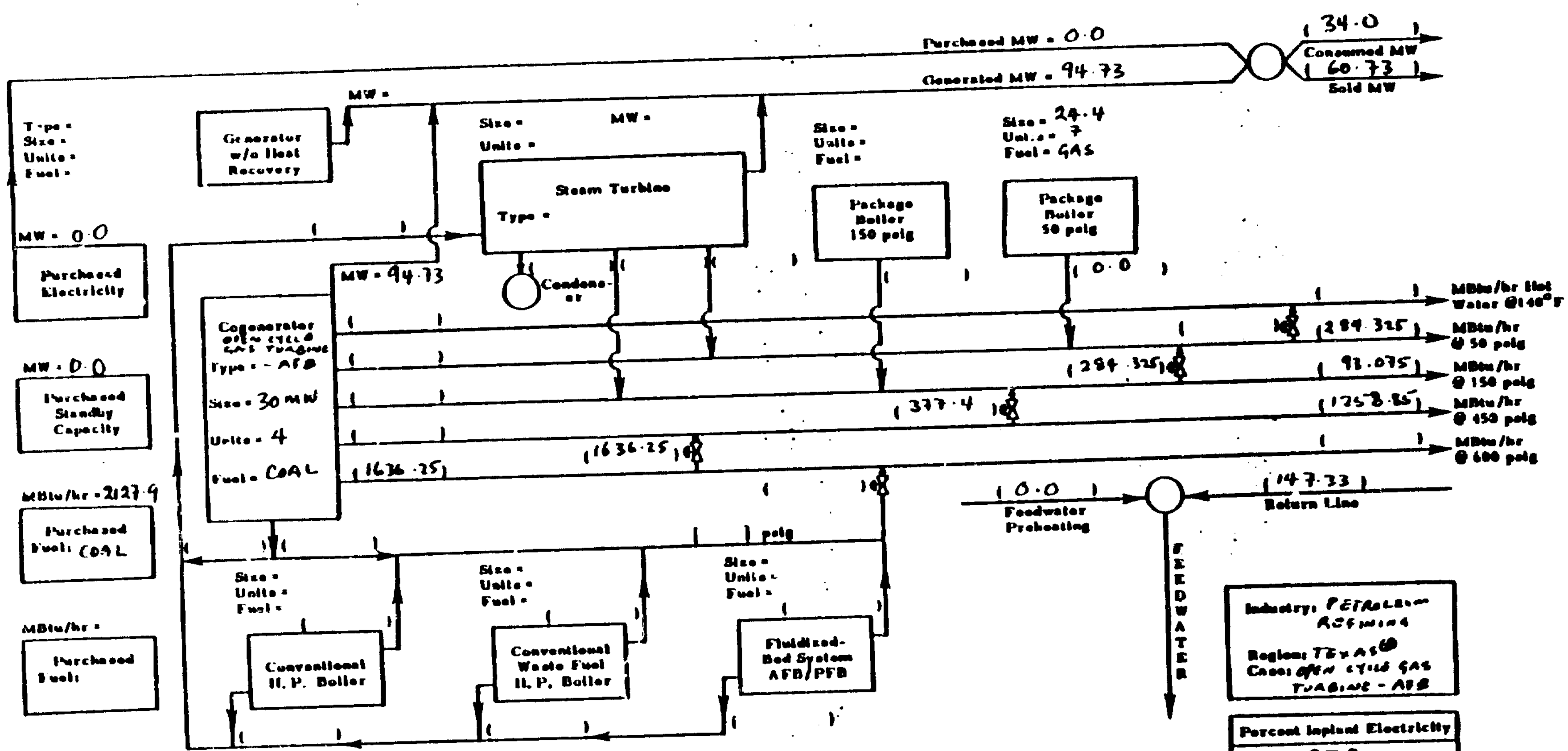
Run Cost $
28.46

DEMANDS	TP	MW Electric	MBtu/hr Hot Water	MBtu/hr 50 psig	MBtu/hr 150 psig	MBtu/hr 450 psig	MBtu/hr 600 psig	MBtu/hr Waste Available	Hours
	02	40		334.50	109.50	1481.00			5419.89

CCEQC	= .1066	
PCOAL	= 2.056	\$/MBtu
PRESIDUAL	= 5.391	\$/MBtu
PDISTILLATE	= 6.894	\$/MBtu
PGAS	= 4.440	\$/MBtu
PELECD	= 1.789	\$/kW/mo
PELECE	= .036	\$/kWh
PSTDBY	= 2.000	\$/kW/mo
PSELL	= .023	\$/kWh

MBtu = million Btu
M$ = million dollars

ⓔ SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN.



DEMANDS	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
	03	34.0		284.325	93.075	1258.85			2090.69
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	

CCEQC	= .1066	
PCOAL	= 2.056	$/MBtu
PRESIDUAL	= 5.381	$/MBtu
PDISTILLATE	= 6.899	$/MBtu
PGAS	= 4.440	$/MBtu
PELECD	= 1.789	$/kW/mo
PELECE	= .036	$/kWh
PSTDBY	= 2.090	$/kW/mo
PSELL	= .023	$/kWh

Industry: PETROLEUM REFINING
Region: TEXAS①
Case: OPEN CYCLE GAS TURBINE - AFB

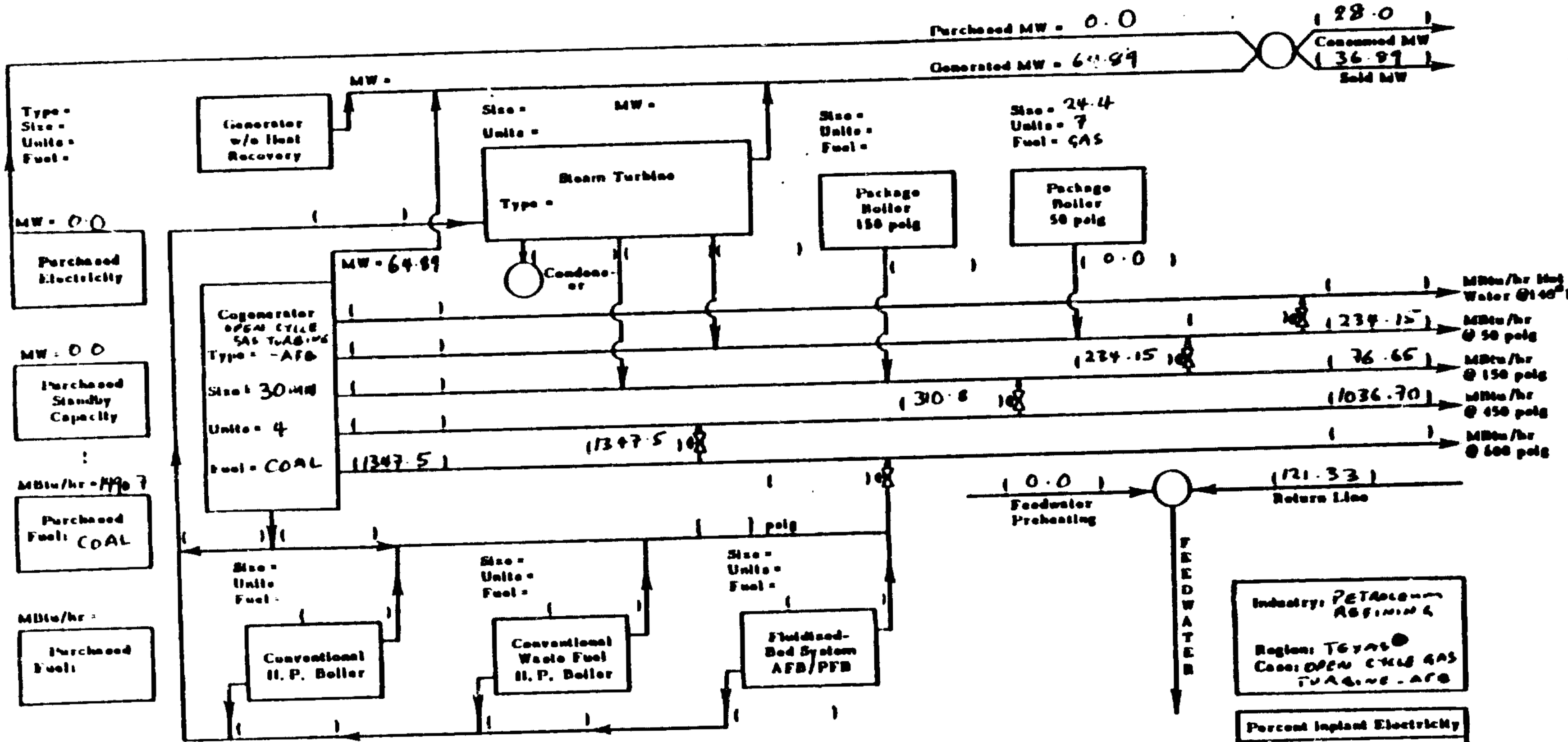
Percent Inplant Electricity
278.6

Annual Plant Cost M$
56.64

Run Cost $
28.46

MBtu = million Btu
M$ = million dollars

① SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN.



	TP	MW	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	MBtu/hr	Hours
		Electric	Hot Water	50 psig	150 psig	450 psig	600 psig	Waste Available	
D E M A N D S									
	64	28.0		234.15	76.65	1036.70			418.14

CCEQC = .1066
PCOAL = 2.056 $/MBtu
PRESIDUAL = 5.381 $/MBtu
PDISTILLATE = 6.894 $/MBtu
PGAS = 4.490 $/MBtu
PELECD = 1.789 $/kW/mo
PELECE = .036 $/kWh
PSTDBY = 2.000 $/kW/mo
PSELL = .023 $/kWh

Industry: PETROLEUM REFINING
Region: TEXAS ⓔ
Case: OPEN CYCLE GAS TURBINE - AFB

Percent Inplant Electricity
231.8

Annual Plant Cost M$
56.64

Run Cost $
28.46

MBtu = million Btu
M$ = million dollars

ⓔ SAME ENERGY FLOWS AS IN THE NATIONAL AVERAGE RUN.

APPENDIX A

Cost and Performance Data

for the

Advanced Energy Conversior

Table A1

ECS: Advanced Open Cycle Gas Turbine with Coal Derived Residual

Size	Full Load Performance						Costs	
	Efficiency η	Q process/Q fuel-in					Capital Cost $/kWe	O & M Cost $/kW-hr.
		600 psig	450 psig	150 psig	50 psig	Hot Water		
1 MWe	.280	.525	0	0	0	0	683.9	2.9×10^{-3}
5 MWe	.325	.490	0	0	0	0	480.0	2.9×10^{-3}
10 MWe	.330	.485	0	0	0	0	412.1	2.9×10^{-3}
30 MWe	.330	.485	0	0	0	0	323.6	2.9×10^{-3}
50 MWe	.330	.485	0	0	0	0	289.2	2.9×10^{-3}
100 MWe	.330	.485	0	0	0	0	248.3	2.9×10^{-3}

Part Load Performance as a Fraction of Full Load Performance

% of Load						
80	.964	1.013	-	-	-	-
60	.896	1.040	-	-	-	-
40	.779	1.086	-	-	-	-

Table A2

ECS: Advanced Open Cycle Gas Turbine with Integrated Gasifier

Size	Full Load Performance						Costs	
	Efficiency η	Q process/Q fuel-in					Capital Cost \$/kWe	O & M Cost \$/kW-hr.
		600 psig	450 psig	150 psig	50 psig	Hot Water		
10 MWe	.190	.593	0	0	0	0	1592.9	3.1×10^{-3}
30 MWe	.190	.593	0	0	0	0	1264.7	3.1×10^{-3}
50 MWe	.190	.593	0	0	0	0	1136.1	3.1×10^{-3}
100 MWe	.190	.593	0	0	0	0	982.2	3.1×10^{-3}

C-3

Table A3

ECS: Advanced Open Cycle Gas Turbine with AFB

Size	Full Load Performance						Costs	
	Efficiency n	Q process/Q fuel-in					Capital Cost $/kWe	O & M Cost $/kW-hr.
		600 psig	450 psig	150 psig	50 psig	Hot Water		
10 MWe	.160	.668	0	0	0	0	1699.8	7.3×10^{-3}
30 MWe	.160	.668	0	0	0	0	1379.6	7.3×10^{-3}
50 MWe	.160	.668	0	0	0	0	1252.0	7.3×10^{-3}
100 MWe	.160	.668	0	0	0	0	1097.5	7.3×10^{-3}

Part Load Performance as a Fraction
of Full Load Performance

% of Load						
80	.921	1.013	-	-	-	-
60	.821	1.030	-	-	-	-

Table A4

ECS: Advanced Open Cycle Gas Turbine with PFB

Size	Full Load Performance						Costs	
	Efficiency n	Q process/Q fuel-in 600 psig	450 psig	150 psig	50 psig	Hot Water	Capital Cost $/kWe	O & M Cost $/kW-hr.
10 MWe	.195	.585	0	0	0	0	1476.8	7.9×10^{-3}
30 MWe	.195	.585	0	0	0	0	1185.5	7.9×10^{-3}
50 MWe	.195	.585	0	0	0	0	1070.4	7.9×10^{-3}
100 MWe	.195	.585	0	0	0	0	931.8	7.9×10^{-3}

Part Load Performance as a Fraction
of Full Load Performance

% of Load						
80	.923	1.019	-	-	-	-
60	.821	1.043	-	-	-	-

Table A5

ECS: Advanced Closed Cycle Gas Turbine with AFB

	Full Load Performance						Costs	
Size	Efficiency	Q process/Q fuel-in					Capital Cost	O & M Cost
	n	600 psig	450 psig	150 psig	50 psig	Hot Water	\$/kWe	\$/kW-hr.
10 MWe	.230	.322	.027	.064	.044	.137	1300.0	5.6×10^{-3}
30 MWe	.240	.320	.057	.030	.043	.140	1009.7	5.6×10^{-3}
50 MWe	.240	.320	.057	.030	.043	.140	897.8	5.6×10^{-3}
100 MWe	.240	.320	.057	.030	.043	.140	765.5	5.6×10^{-3}

Part Load Performance as a Fraction
of Full Load Performance

% of Load						
80	1.000	1.000	1.000	1.000	1.000	1.000
60	.983	1.005	1.005	1.005	1.000	1.007
40	.909	1.027	1.027	1.027	1.022	1.030

Table A6

ECS: Molten Carbonate Fuel Cell with Coal Derived Distillate

Size	Full Load Performance						Costs	
	Efficiency n	Q process/Q fuel-in					Capital Cost $/kWe	O & M Cost $/kW-hr.
		600 psig	450 psig	150 psig	50 psig	Hot Water		
1 MWe	.359	.406	.002	.005	.003	.115	733.7	2.6×10^{-3}
5 MWe	.359	.431	.002	.005	.003	.090	651.3	2.6×10^{-3}
10 MWe	.359	.431	.002	.005	.003	.090	618.7	2.6×10^{-3}
30 MWe	.359	.431	.002	.005	.003	.090	570.4	2.6×10^{-3}
50 MWe	.359	.431	.002	.005	.003	.090	549.3	2.6×10^{-3}
100 MWe	.359	.431	.002	.005	.003	.090	521.8	2.6×10^{-3}

Part Load Performance as a Fraction of Full Load Performance

% of Load						
80	1.053	.971	.971	.971	1.000	.967
60	1.047	.974	.974	.974	1.000	.973
40	.930	1.040	1.040	1.040	1.000	1.040

Table A7

ECS: Molten Carbonate Fuel Cell with Integrated Gasifier

Size	Full Load Performance						Costs	
	Efficiency n	Q process/Q fuel-in					Capital Cost $/kWe	O & M Cost $/kW-hr.
		600 psig	450 psig	150 psig	50 psig	Hot Water		
10 MWe	.276	.354	.006	.014	.010	.150	1806.1	3.3×10^{-3}
30 MWe	.276	.354	.006	.014	.010	.150	1465.8	3.3×10^{-3}
50 MWe	.276	.354	.006	.014	.010	.150	1330.2	3.3×10^{-3}
100 MWe	.276	.354	.006	.011	.008	.155	1166.1	3.3×10^{-3}

Table A8

ECS: Advanced Gas Turbine for Combined Cycle
Parameters: 2500°F, Pr = 18:1 Coal Derived Residual

Size	Efficiency ECS	Q throttle/Q fuel-in 865 psia/825°F Throttle	Q throttle/Q fuel-in 865 psia/825°F D.A. Heating	Q throttle/Q fuel-in 1465 psia/950°F Throttle	Q throttle/Q fuel-in 1465 psia/950°F D.A. Heating	Capital Cost \$/kWe	O & M Cost \$/kW-hr.
10 MWe	.330	.426	.041	.403	.040	412.1	2.9×10^{-3}
100 MWe	.330	.426	.041	.403	.040	248.3	2.9×10^{-3}

Up to four gas turbines with one steam turbine.

Table A9

AFB Furnace Subsystem (Boiler)

Conditions	Full-Load Performance: X – Steam Flow (1000 lb/hr)	$Q_{throttle}$ – Heat to Steam (10^6 Btu/hr)	n – Electrical Efficiency	R – Electrical Output (MWe)	U – Q throttle / Q fuel-in	hp/U' – hp-hw	Costs: Capital Cost $/$10^6$ Btu/hr	Capital Cost $ x 10^6
615 psia/750°F	100	116.0	-	-	.85	1158.6	5.697×10^4	6.61
hp = 1378.6	200	231.7	-	-	.85	1158.6	5.029×10^4	11.66
	300	347.9	-	-	.85	1158.6	4.675×10^4	16.26
	400	463.9	-	-	.85	1158.6	4.439×10^4	20.59
865 psia/825°F	100	119.1	-	-	.85	1189.9	5.670×10^4	6.75
hp = 1409.9	600	714.5	-	-	.85	1189.9	4.110×10^4	29.37
	1200	1429.0	-	-	.85	1189.9	3.628×10^4	51.84
	1700	2024.5	-	-	.85	1189.9	3.407×10^4	68.97
1465 psia/950°F	600	745.2	-	-	.85	1240.9	4.079×10^4	30.40
hp = 1460.9	1000	1242.1	-	-	.85	1240.9	3.721×10^4	46.22
	1300	1614.7	-	-	.85	1240.9	3.549×10^4	57.31
	1700	2111.5	-	-	.85	1240.9	3.382×10^4	71.41

% of Load	Q Throttle/Q Fuel-In	Electrical Efficiency
80	.858	-
60	.862	-
40	.860	-
20	.842	-

Ta A10

PFB Furnace Subsystem (Boiler with Gas Turbine)

	Full-Load Performance						Costs	
	X	$Q_{throttle}$	n	R	U	hp/U'		
Conditions	Steam Flow (1000 lb/hr)	Heat to Steam (10^6 Btu/hr)	Electrical Efficiency	Electrical Output (MWe)	Q throttle / Q fuel-in	hp-hw	Capital Cost $/$10^6$ Btu/hr	Capital Cost $ x 10^6
615 psia/750°F	100	116.0	.089	3.90	.775	1158.6	11.688×10^4	12.56
hp = 1378.6	200	231.9	.089	7.80	.775	1158.6	9.172×10^4	21.27
	300	347.9	.089	11.71	.775	1158.6	7.958×10^4	29.69
	400	463.9	.089	15.61	.775	1158.6	7.195×10^4	33.38
865 psia/825°F	100	119.1	.089	4.01	.775	1189.9	11.581×10^4	13.79
hp = 1409.9	600	714.5	.089	24.04	.775	1189.9	6.164×10^4	44.09
	1200	1429.0	.089	48.08	.775	1189.9	4.836×10^4	69.11
	1700	2024.5	.089	68.12	.775	1189.9	4.281×10^4	86.67
1465 psia/950°F	600	745.2	.089	25.07	.775	1240.9	6.073×10^4	45.26
hp = 1460.9	1000	1242.1	.089	41.79	.775	1240.9	5.079×10^4	63.09
	1300	1614.7	.089	41.79	.775	1240.9	4.634×10^4	74.83
	1700	2111.5	.089	71.05	.775	1240.9	4.218×10^4	89.06

Part Load Performance

% of Load	Q Throttle/Q Fuel-In	Electrical Efficiency
.8	.774	.089
.6	.773	.089
.4	.771	.089
.3	.770	.088

APPENDIX B

The Optimization Methodology

Method of Optimization

The model is optimized using the Mixed Integer Programming technique implemented in IBM's MPSX program. This technique partitions the optimization into two levels: a higher level problem dealing with the integer variables; and a lower level where all variables are assumed continuous.

The lower level problems are characterized as ordinary continuous linear programming problems which can be efficiently solved using the simplex algorithm. The higher level problem is a pure integer optimization which is solved using a branch-and-bound (B&B) algorithm in which each branch node designates a new lower level problem.

The MIP procedure begins at the base node of the B&B tree. This designates a continuous problem consisting of a physical model with all integer requirements ignored. The solution to this artificial problem will obviously be a lower bound to the optimal solution to the real problem, since the real problem consists of the physical model plus additional constraints requiring that certain variables take on integral values. (A fundamental principle of optimization is that the objective function cannot improve when constraints are added.)

A branch-and-bound algorithm constructs a tree of branches away from this base node by successively adding constraints and solving each slightly more constrained problem; its efficiency depends on the rules used to decide where and how to branch.

In the MPSX-MIP implementation each node leads to two branches on which complementary constraints are imposed. For example, if a supposedly integer variable is still free on the range 2 to 6, one branch might

restrict it from 2 to 4 and the other from 5 to 6. These branches designate two new nodes descending from the previous one, with two new continuous subproblems to be solved, neither of which can have a better objective function than the parent.

After each of the two nodes are evaluated a new branching decision is made, generally descending from the "better" of the two latest nodes. Clearly after a finite number of stages every necessary variable can be forced to be integral by a pair of constraints requiring it to be both no greater than and no less than some integer. With luck many variables will naturally ride up against the integral end of a constraint range and not require to be forced.

The objective function value of the subproblem at this node will constitute an upper bound on the optimal solution of the real problem, since it meets all the physical and integrality constraints but may not have the best values for the integer variables. (That is, it may be overconstrained, since the B&B forces particular integral values at the node while the real problem allows any value that is integer.)

However, a node at which all the necessary variables are integer is definitely optimal if its objective function value is not greater than that of any other not-yet-integerized branch. At such a pending node the objective function value is only a lower bound, and it is possible that a properly integer solution might exist beneath it with no worse a value. (The added descending constraints cannot lower the value, but they need not raise it.)

The branch-and-bound algorithm selectively explores nodes with good lower bounds and branches from them until either a properly integer

solution is found or the lower bound becomes greater than the best proper objective function found so far. When no pending node has a lower bound below the best integer solution, then the algorithm terminates.

The progress of the MPSX-MIP procedure can then be monitored by keeping track of the overall lower bound and the overall upper bound. The overall lower bound is the least lower bound on any unexplored node with non-integral variables. At any given time during the optimization the possibility that the real optimum might be that low cannot be ruled out. The overall lower bound is initially equal to the objective function of the base node, found by relaxing all the integer constraints. The overall upper bound is the least objective function among any properly integer solutions. At any given time during the optimization it is certain that the real optimum will not exceed this value. An upper bound is not known until the first properly integral solution has been found. Note that the optimal solution is generally discovered some time before optimality is proven; the extra time is spent pushing the lower bounds of the remaining pending nodes up through the optimal ceiling.

Several examples of this optimization process were studied during the preliminary model development phases of the study. Plots of the progress of these optimizations are shown in Figures B1, B2, and B3. Each of these figures plots the point of discovery of each improved lower bound and upper bound. Three axes are provided to measure the effort expended: the search time (CPU time on the computer), the total number of branch nodes explored, and the cumulative number of simplex interactions in the subproblems.

The three figures are similar in structure: the lower bound creeps up; a better upper bound is found; this allows pending nodes with high

Figure B1

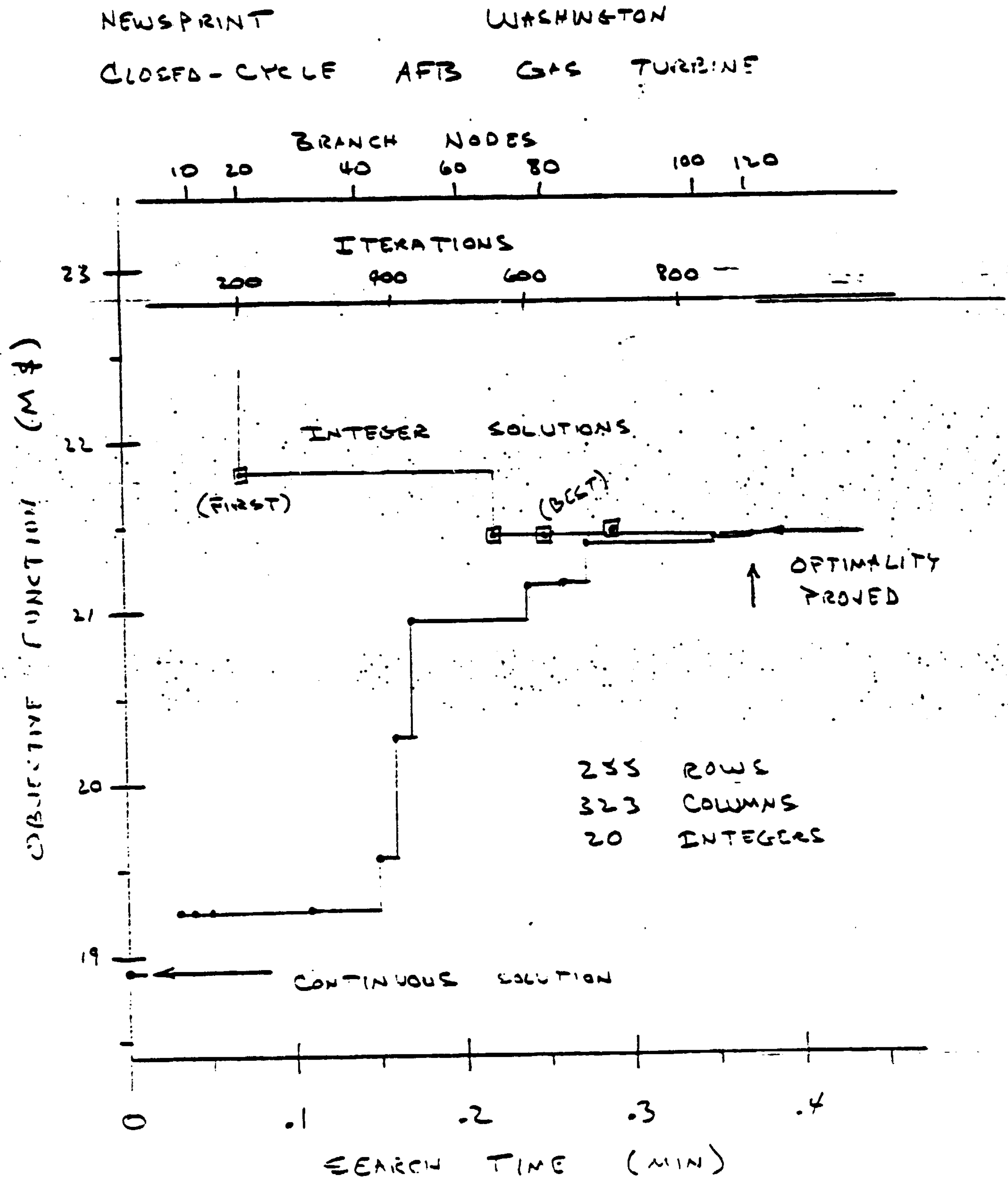

NEWSPRINT
WASHINGTON
CLOSED-CYCLE AFB GAS TURBINE
BRANCH NODES
10 20 40 60 80 100 120
ITERATIONS
200 400 600 800
23
22
21
20
19
OBJECTIVE FUNCTION (M $)
INTEGER SOLUTIONS
(FIRST)
(BEST)
OPTIMALITY PROVED
235 ROWS
323 COLUMNS
20 INTEGERS
CONTINUOUS SOLUTION
0 .1 .2 .3 .4
SEARCH TIME (MIN)

Figure B2

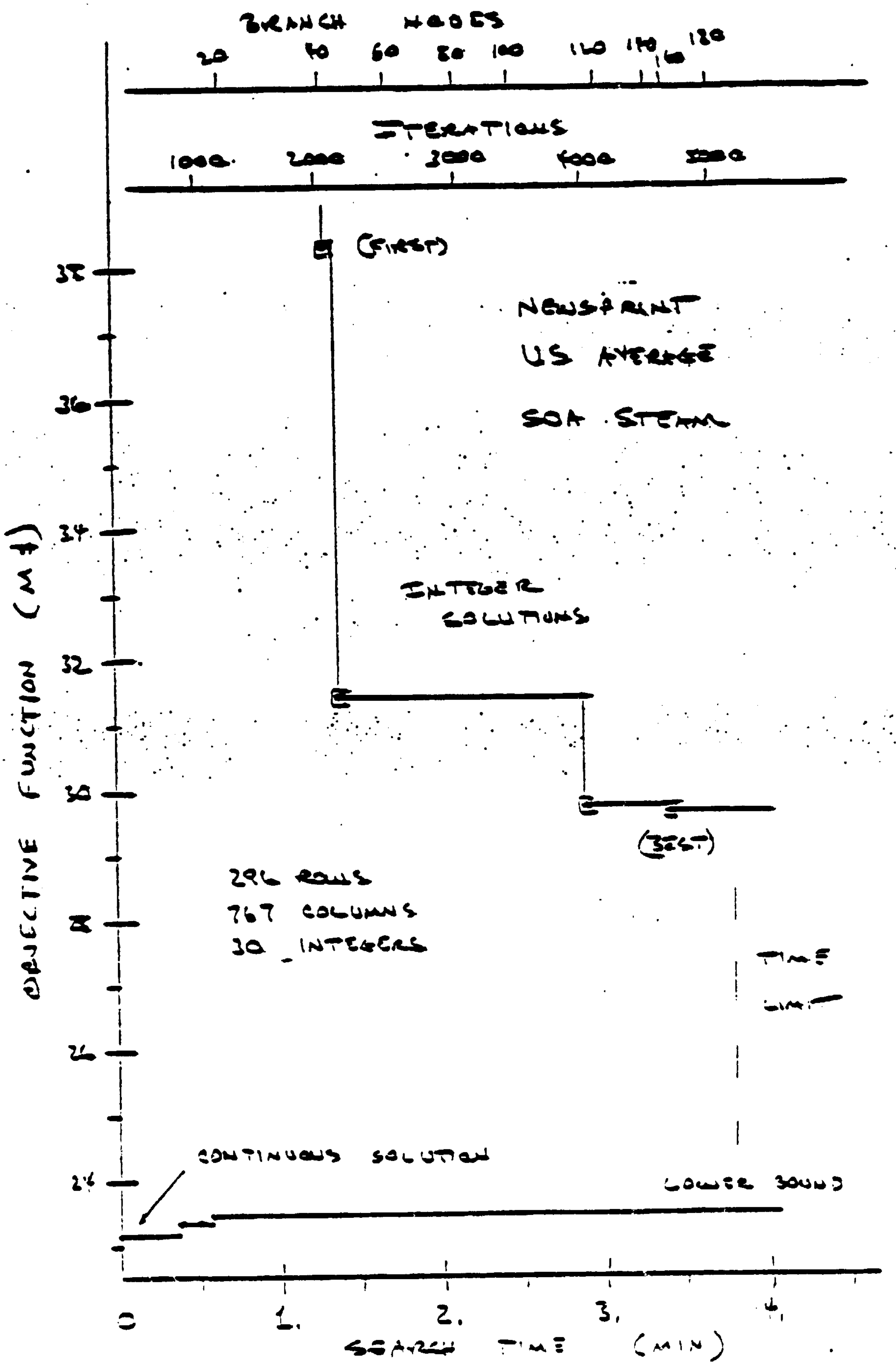
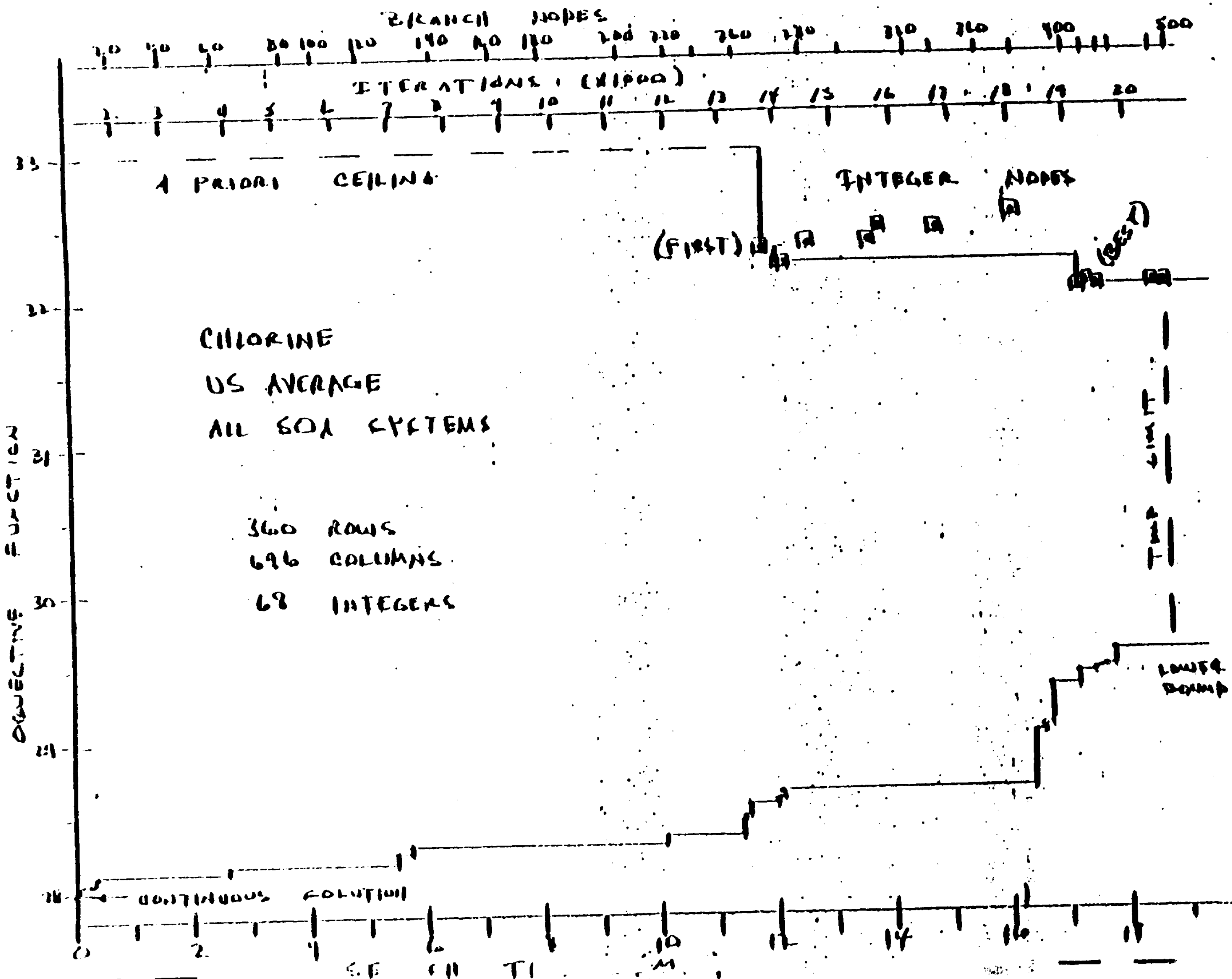

BRANCH NODES
20 40 60 80 100 120 140 160 180
ITERATIONS
1000 2000 3000 4000 5000
(FIRST)
NEWSPRINT
US AVERAGE
SOA STEAM
INTEGER SOLUTIONS
(BEST)
296 ROWS
767 COLUMNS
30 INTEGERS
TIME LIMIT
CONTINUOUS SOLUTION
LOWER BOUND
OBJECTIVE FUNCTION (M $)
38
36
34
32
30
28
26
24
0
1.
2.
3.
4.
SEARCH TIME (MIN)

Figure B3


BRANCH NODES
ITERATIONS (x1000)
A PRIORI CEILING
INTEGER NODES
(FIRST)
CHLORINE
US AVERAGE
ALL SOX SYSTEMS
360 ROWS
696 COLUMNS
68 INTEGERS
CONTINUOUS SOLUTION
LOWER BOUND
OBJECTIVE FUNCTION

lower bounds to be dropped, and the lower bound is then improved; then the upper bound is lowered; etc. The envelope of the lower bound and upper bound points funnels in to the optimal solution value.

Unfortunately the time scales are rather different for these cases. The problem of selecting the best closed-cycle AFB gas turbine was completely optimized in a short time. The optimization of the steam turbine system was terminated by an automatic time limit without proving optimality. Although the lower bound was not much improved beyond its initial value, the pattern of progress suggests that the optimal value would lie near the final upper bound. The most ambitious case was an attempted global optimization among all the state-of-the-art (conventional cogeneration) systems. This was pushed out for a considerable number of iterations but never reached optimality. Its progress was steady and normal, but too slow.